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No. ——

Supreme Court, U.S.
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IN THE

Supreme Court of the United States

OCTOBER TERM, 1990

GULF STATES UTILITIES COMPANY,
Petitioner,

v.

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES,
OFFICE OF PUBLIC UTILITY COUNSEL,
CITY OF BRIDGE CITY, *et al.*, and
PUBLIC UTILITY COMMISSION OF TEXAS,
Respondents.

Petition for Writ of Certiorari to the Supreme Court of Texas

APPENDIX TO PETITION FOR WRIT OF CERTIORARI

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APPENDIX A

IN THE SUPREME COURT OF TEXAS

No. C-9287

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES, *et al.*,

Petitioners,

v.

PUBLIC UTILITY COMMISSION OF TEXAS, *et al.*,

Respondents.

From Travis County
Third District

[September 12, 1990]

OPINION

In this appeal certain consumers of a public utility urge that it be denied a second opportunity to prove the same facts as justification for an electric rate increase. We agree that the public utility regulatory scheme set forth by the legislature provides that once is enough. The doctrines of *res judicata* and collateral estoppel bar such relitigation before the Public Utility Commission ("PUC").

Gulf States Utilities Company ("GSU") sought a rate increase which required the PUC to determine whether the $4.5 billion that GSU spent for completion of the River Bend Nuclear Power Plant was a prudently incurred cost.[1] This expense was challenged by the peti-

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[1] Gulf States' application for authority to change rates, designated docket no. 7195, was consolidated by the Commission with docket no. 6755, which inquired whether the $4.5 billion spent to construct River Bend was a prudently incurred expense.

tioners [2] who intervened in the rate case before the PUC. As GSU has noted, "[e]very factual, legal and policy issue was thoroughly explored and canvassed", during the resulting hearings that continued for 132 days and cost ratepayers approximately $12 million. Thereafter the PUC issued a final order containing the following findings of fact and conclusions of law that are central to the present controversy:

> *Finding 164*: The preponderance of the evidence in this case establishes that $2.273 billion of River Bend capital costs were prudently and reasonably incurred. The evidence is inadequate to support a finding of either prudence or imprudence with regard to construction costs in excess of $2.273 billion, with the exception of the costs related to the 50-month schedule and TDI, addressed in Findings of Fact Nos. 133 and 145.
>
> *Finding 164A*: GSU's share of all River Bend capital costs in excess of $2.273 billion should be excluded from plant in service at this time for lack of sufficient evidence as to the prudence and reasonableness of those costs. The amount which should be included in plant in service, given GSU's 70 percent share of the plant, is $1.5911 billion.
>
> *Conclusion of Law 10*: Pursuant to PURA Sections 16(a), 38, 39(a), and 41,[3] the Commission may reexamine on rehearing or in a subsequent proceeding the prudence and reasonableness of those River Bend

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[2] The petitioners are Coalition of Cities for Affordable Utility Rates ("Coalition") representing West Orange, Conroe, Panorama Village, Willis, Cut-N-Shoot and Somerville; the Cities of Bridge City, Groves, Nederland, Port Arthur, Port Neches and Vidor; and the Office of Public Utility Counsel.

[3] The Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1990), will be referenced as PURA throughout the opinion.

construction costs regarding which the evidence is inadequate to support a finding of either prudence or imprudence.

Conclusion of Law 15: Under PURA Section 40 a utility must prove its conduct to have been prudent when decisions or expenditures are reasonably challenged.

Conclusion of Law 18: $1,453,520,982 of GSU's share of end-of-test-year River Bend capital costs should not be included from GSU's rate base as invested capital used and useful in rendering service to the public pursuant to PURA Sections 38, 39, and 41.

Conclusion of Law 18A: GSU has not met its burden of proving that the capital costs of River Bend above a reasonable Definitive Cost Estimate of $2.273 billion were reasonably and prudently incurred.

In summary, the PUC found that GSU had failed to prove that any expenses in excess of $2.273 billion were prudently incurred. Two of the three commissioners voted to allow GSU further opportunity to prove the prudence of an additional $1.453 billion, which apparently represented GSU's share of cost overruns on the project. In taking this action, the PUC rejected its hearing examiner's proposed conclusion of law that *res judicata* would prohibit reexamination of the prudence issue.

GSU appealed the final order and simultaneously initiated a new proceeding before the PUC on the same prudence question.[4] The petitioners also appealed and, based on *res judicata*, obtained from the trial court a

[4] The consolidated administrative appeal of GSU and the petitioners is currently pending in the 250th District Court of Travis County as cause no. 447,502. The action before us was severed from that cause and assigned cause no. 447,502A. The new docket granted by the Commission to relitigate the prudence issue has been designated as docket no. 8702.

permanent injunction preventing further consideration of this issue by the PUC. The court of appeals, however, dissolved the permanent injunction and ruled that the doctrine of *res judicata* was inapplicable because the PUC had specifically reserved the right to rehear the prudence issue in conclusion of law 10. 777 S.W.2d 814, 816. The court cited no authority to support its *res judicata* holding, but merely compared the PUC action to a severance authorized by Texas Rule of Civil Procedure 41. *Id.* at 817. Because we disagree with this conclusion, we reverse the court of appeals' judgment.

In *Bonniwell v. Beech Aircraft Corp.*, 663 S.W.2d 816, 818 (Tex. 1984), we considered the doctrines of *res judicata* and collateral estoppel. *Res judicata*, a matter judicially determined, bars the retrial of claims pertaining to the same cause of action which has been finally adjudicated. Collateral estoppel or issue preclusion is more narrow, precluding only the relitigation of identical issues of fact that have been actually litigated. To invoke either doctrine, the prior judgment must involve, the same issues, subject matter, and parties or those in privity.

Texas has made limited use of *res judicata* in an administrative context.[5] *See Sexton v. Mount Olivet Cemetery Ass'n*, 720 S.W.2d 129, 138-142 (Tex. App.—Austin 1986, writ ref'd n.r.e.). Voicing an awareness of the usefulness of *res judicata* in administrative proceedings, this court in *Westheimer Indep. School Dist. v. Brockette*, 567 S.W.2d 780, 787 (Tex. 1987), expressed a strong preference that "[c]ontinued litigation of is-

---

[5] By narrowly applying *res judicata* to historical investment facts in a ratemaking proceeding under the conditions set forth herein, today's opinion continues this tradition of the restricted use of *res judicata* in administrative proceedings. Contrary to the suggestion of the dissent, the Court is in no way "impart[ing] collateral estoppel and res judicata effect on all actions and *inactions* by admintrative agencies." —— S.W.2d —— (Gonzalez, J., dissenting).

sues or piecemeal litigation should be discouraged" in state regulatory agencies.

Ironically, GSU was the first party to urge the applicability of *res judicata* and collateral estoppel in this proceeding. GSU maintained initially that the doctrines precluded the PUC from considering the prudence of the River Bend construction, which it had previously authorized by granting a certificate of convenience and necessity. Additionally, counsel for the PUC acknowledged during oral arguments before this court that *res judicata* would prohibit relitigation regarding the $2.273 billion found prudent by the PUC. Petitioners correctly characterize the PUC's position as seeking to apply *res judicata* to the portion of costs that GSU proved and rejecting its application to costs not proved.

Excepting the oral argument of counsel for GSU, everyone involved in these proceedings agrees with the court of appeals that *res judicata* could apply to PUC ratemaking "[u]nder proper circumstances. . . ." 777 S.W.2d at 815. The more narrow question we confront is whether the doctrine should be rejected because of any aspect of this particular proceeding, the PUC's final order, or the statute by which the order was authorized. At issue here is not increased operating expenses or the appropriate rate of return—factors that can change over time. Rather, every fact involved is historical; the amount and wisdom of these construction expenditures will remain constant no matter how many times the PUC permits relitigation addressing them. All of the same parties participated vigorously in the initial contest with each presenting its own evidence and cross-examining its opponent's witnesses. Were this not true, imposition of *res judicata* principles would be inappropriate.

Given these circumstances, if the PUC's final order had been unequivocal, there could be no question that the doctrine applies. But is it precluded by the PUC's conclusion of law 10, permitting further proceedings and attempting

a deferral rather than a determination of the issue? In answering this question we look first to the terms of the order and the controversy it addresses. A utility has the burden to prove the prudence and reasonableness of its expenditures before a rate increase can be approved. PURA § 40; *see also Public Util. Comm'n v. Houston Lighting & Power Co.*, 778 S.W.2d 195, 198 (Tex. App.—Austin 1989, no writ). By simply opening its books to inspection, a utility enjoys no presumption that the expenditures reflected therein have been prudently incurred. A utility carries the burden of proof even when it does not initiate the proceedings. *Suburban Util. Corp. v. Public Util. Comm'n*, 652 S.W.2d 358, 366 (Tex. 1983).

In this rate case, the PUC declared that GSU failed to meet its burden of proof to show that the entire $4.5 billion expense was prudently incurred. Because of a "lack of sufficient evidence", the PUC, in its finding 164A, "excluded from plant in service" all "capital costs in excess of $2.273 billion." A party who fails to meet its burden of proof loses. The party who has the burden but fails to persuade the trier of fact is not entitled to a second trial to present more evidence. By stating that GSU failed to meet its burden of proof on the prudence of the $1.453 billion, the PUC effectively disallowed that amount from the rate base. *See Gerst v. Goldsbury*, 434 S.W.2d 665, 667 (Tex. 1967) (agency determination that applicant offered "insufficient evidence of a public need for the proposed [savings] association" constituted a "negative finding").

More importantly, the PUC order must be considered final unless the PUC has the statutory power to defer and reconsider such critical issues. Such was the holding in *Sexton v. Mount Olivet Cemetery Ass'n*, 720 S.W.2d at 146, in which the Banking Commissioner sought to revisit an issue determined in a prior order relating to prepaid funeral plan regulation. As in the instant case, the order had expressly reserved the discretion to make

new determinations at a later time. Refusing to permit a reopening of the final order, the court held that an attempted reservation of power is meaningless unless the legislature has specifically delegated such authority to an agency.

The PUC sought to base its attempted reservation of the right to reconsider the cost question presented by GSU on PURA sections 16(a), 38, 39(a), and 41. Nothing contained in sections 38, 39(a) and 41, either directly or indirectly, entitles the PUC to grant a utility multiple chances to prove the prudence of its investment. Section 16(a) does state the PUC's power "to do all things, whether specifically designated by this Act or implied herein, necessary and convenient to the exercise of this power and jurisdiction." It was hardly *necessary* to initiate a new docket to consider the $1.453 billion since the PUC could have sought additional guidance by remanding to the hearing examiner for further development of the evidence. Moreover, the PUC can only do what is *necessary* and *convenient* with regard to powers "specifically designated . . . or implied herein . . ." by other provisions of PURA. There is no language in this or any other section of PURA that allows the PUC to bifurcate into multiple proceedings the issue of a single investment's prudence.

The only legislative authorization for PUC reexamination of an earlier determination concerns the power to revoke or amend a certificate of convenience and necessity under certain circumstances outlined in PURA section 62(a). This section represents a clear delegation of authority for the PUC to reopen a matter previously considered. The legislature was, thus, quite capable of expressly approving the PUC reexamination of earlier determinations, but chose not to extend this authority to ratemaking. Thus, limited by statute and lacking any inherent power, the PUC was powerless to defer its decision to a future proceeding.

The court of appeals was correct in characterizing the ratemaking proceeding as a trial, but incorrect in comparing the PUC action in conclusion of law 10 "to that of the trial court in severing a claim and proceeding separately with it. Tex. R. Civ. P. 41." 777 S.W.2d at 817. Severance in a trial court is proper only when the suit involves two or more separate and distinct causes of action. Each of these causes must be such that it could be properly tried and determined as if it were the only claim in controversy. *Kansas Univ. Endowment Ass'n v. King*, 162 Tex. 599, 611-612, 350 S.W.2d 11, 19 (1961). The severed causes of action should not be so interwoven as to require the introduction of evidence on the same facts and issues. Furthermore, severance should not be used merely as a device to save a party from failure to prepare properly for trial or to present adequate evidence. Nor does Rule 41 permit a trial court to sever a case after it has been submitted to the trier of fact. That is the type of "severance" the PUC directed here. What happened in this case is more appropriately compared to an improper post-trial attempt to split a cause of action. Nothing in either PURA or the Administrative Practice and Texas Register Act, Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1990), allows a division of the investment rate base in ratemaking proceedings.[6]

Once the order in the intial docket became final, it was not subject to any further PUC review. *Public Util. Comm'n v. Brazos Elec. Power Coop., Inc.*, 723 S.W.2d 171, 173 (Tex. App.—Austin 1986, writ ref'd n.r.e.). The prudence of spending the entire $4.5 billion to con-

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[6] We note the difference between a "separate trial" and a "severance". *Compare* Tex. R. Civ. P. 40(b) *with* Tex. R. Civ. P. 41. The PUC did not decide at the onset of the initial docket to hc'd separate hearings on various issues in a manner comparable to Rule 40(b). Rather its conduct was analogous to splitting a cause of action after submission to the trier of fact in violation of Rule 41.

struct the River Bend Nuclear Power Plant had already been vigorously litigated in hearings that afforded GSU ample opportunity to justify all of its costs. The thrust of the new proceeding was to separate for reconsideration the prudence of $1.453 billion of this expenditure, a part of the total investment. This portion, representing GSU's share of cost overruns, had necessarily been previously considered.

All parties were entitled to a straightforward decision from the PUC the first time that this case was presented. Permitting relitigation offends the policy reasons supporting the doctrines of *res judicata* and collateral estoppel. Both a public utility and consumers benefit from a final decision about whether cost overruns at a power plant have been sufficiently justified. With a complex and controversial project like a nuclear power installation, a utility and its investors need a determination to prevent relitigation of the same previous investment decision on each occasion that a rate increase is requested. The same finality that benefits the utility investors can serve the interests of consumers who know that if a utility is once denied relief because of its failure to prove its case, it may not return repeatedly on the same facts until the PUC yields. To reject *res judicata* for historical investment facts in a ratemaking proceeding would allow a public utility to secure victory not by the strength of its case but simply by outlasting its opponents. Accordingly, we hold that the doctrines of *res judicata* and collateral estoppel bar a utility from relitigating before the PUC the prudence of its past investment for inclusion in that utility's rate base. We reverse the judgment of the court of appeals and affirm that of the trial court.[7]

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[7] All issues relating to the merits of the administrative order, including the prudence of all elements of construction costs, remain to be addressed by the trial court where the consolidated appeals of the parties are pending as cause no. 447,502. In this proceeding the burden is upon GSU to show that the PUC's order is not sup-

/s/

LLOYD DOGGETT
Justice

Dissent by Justice Gonzalez joined by Justice Cook

Opinion Delivered: September 12, 1990

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ported by substantial evidence. The claim of the dissent that we have at this point "assess[ed] a $1.543 billion penalty (permanent disallowance) on GSU", —— S.W.2d —— (Gonzalez, J., dissenting), is incorrect.

IN THE SUPREME COURT OF TEXAS

No. C-9287

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES, *et al.*,

Petitioners,

v.

PUBLIC UTILITY COMMISSION OF TEXAS, *et al.*,

Respondents.

From Travis County
Third District

[September 12, 1990]

DISSENTING OPINION

I agree with the court that a litigant involved in an administrative hearing is entitled to only one adjudication. I disagree, however, that there has been a valid adjudication in this case.[1] I also agree with the court that the Commission is not authorized to defer deciding or to sever part of the issue in question. However, no matter how erroneous this severance or deferral was, we should not penalize a litigant for an error made by the Commission through no fault of the litigant. Since the Commission made only a partial determination of what costs were reasonable and prudent and held in abeyance

[1] GSU claimed that the $4.5 billion spent on the nuclear project was reasonably and prudently incurred. The Commission decided to defer making a decision of whether any cost in excess of $2.273 billion (adjusted cost estimate) were prudently incurred. It was the Commission's expressed intent to review the prudence or imprudence of the additional cost in a subsequent proceeding.

the balance of the issue, it is inappropriate to apply the principles of res judicata and collateral estoppel to *any* portion of this case. I would affirm the courts of appeals dissolution of the permanent injunction.[2] However, I would not allow the litigants to present further evidence

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[2] The determination of the prudence of the entire $4.5 billion expenditure has resulted in a multiplicity of suits because the Commission effectively severed its decision as to the portion of costs it determined were prudent from those it reserved for further proceedings. Those cases were docketed in the Commission as #6755 (request for determination regarding prudence of $4.5 billion River Bend expenditure), #7195 (GSU's original application to change rates), and #8702 (determination of prudence of $1.453 billion balance). The Commission consolidated #6755 and #7195 because a determination of the prudence of the expenditures was necessary to set the new rates. After the Commission determined the $2.273 billion expenditure was prudent but left open the balance, the judgment was appealed to the district court.

While that proceeding was pending, the Commission scheduled proceeding #8702 to determine the prudence of the $1.453 billion. The district court issued a temporary injunction enjoining any relitigation of the prudence of the Riverbend [sic] expenditures. While the granting of this temporary injunction was on appeal to the court of appeals, the district court granted a permanent injunction stating the relitigation of the prudence issue was barred by res judicata and collateral estoppel and the relitigation would interfere with the district court's jurisdiction over the prudence issue in the administrative appeal of #6755 and #7195. This case comes to us on appeal from the court of appeals decision dissolving the permanent injunction because *res judicata* and collateral estoppel did not bar determination of prudence of the balance of the costs.

Let us end this madness! Since we have settled the issue that the severance was improper, the district court does not have a choice but to follow suit. I would dissolve the injunction but suggest to the parties that they file a plea in abatement in the commission pending remand by the district court of the case now on appeal. Our decision affirming this case would return the *entire case* to the Commission and allow it to make a *single final adjudication* regarding the entire $4.5 billion expenditure.

If the Commission should find that some additional costs were prudent, GSU should not be given a windfall. The Commission should adjust the rates keeping in mind the money already collected based on approved rates.

because they have had a full and fair opportunity to participate in the adjudicatory process. I would instruct the Commission to make a valid adjudication based on the record as it now exists.[3] Under no circumstances would I apply res judicata and collateral estoppel to this case.

Res judicata makes final a matter which has been finally adjudged on its merits. See *Abbott Laboratories v. Gravis*, 470 S.W.2d 639, 642 (Tex. 1971). Collateral estoppel is a much narrower doctrine pertaining to the preclusion of issues. We have said that a party to a lawsuit may invoke the doctrine by establishing:

> (1) the facts sought to be litigated in the second action were fully and fairly litigated in the prior action; (2) those facts were essential to the judgment in the first action; and (3) the parties were cast as adversaries in the first action.

Bonniwell v. Beech Aircraft Corp., 663 S.W.2d 816, 818 (Tex. 1984). In short, res judicata prevents the relitigation of adjudicated claims (claim preclusion) and collateral estoppel bars the relitigation of adjudicated issues (issue preclusion). An essential element of both doctrines is that the rendering tribunal actually determined the issue or claim to be precluded on its own merits.

There are several indicators that support the court's of appeals conclusion that the Commission postponed making a decision on a major portion of GSU's claim:

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[3] I recognize that the end result may ultimately be the same as that which has already been achieved. The Commission may decide that none of the expenditures in excess of $2.273 billion were prudent. That is its prerogative. We are powerless to make an independent finding on this matter. We should respect the limits of our authority. Also, since this is a case of first impression in Texas, we should dissolve the permanent injunction and permit the Commission to decide the entire case as a whole in order to achieve fairness and to facilitate the orderly development of this important area of administrative law.

1. The Commission argues that it made no decision on the prudence or imprudence of cost in excess of $2.273 billion.

2. The record shows as follows:

(a) The Commission adopted the examiner's findings of fact and conclusions of law in large part but modified some of them in very significant ways. The Commission **refused to adopt** the examiner's proposed conclusion of law 10 which would have provided that the doctrine of res judicata would preclude relitigation of any of the River Bend prudence issues.

(b) The Commission **refused to adopt the examiner's proposed finding 164 which recommended a disallowance of** $274,015,089. Instead, the Commission made its own finding 164 and 164(a) and conclusion of law 10.

(c) Finding of fact 164 states that "[t]he preponderance of the evidence in this case establishes that [$]2.273 billion of River Bend capital costs were prudently and reasonably incurred. The evidence is inadequate to support a finding of *either prudence or imprudence* with regard to construction costs in excess of $2.273 billion . . ."

(d) Finding of fact 164A states ". . . costs in excess of $2.273 billion should be excluded from plant in service AT THIS TIME for lack of sufficient evidence as to the prudence and reasonableness of those costs."

(e) Conclusion of law 10 states that "[P]ursuant to PURA Sections 16(a), 38, 39(a) and 41, the Commission may reexamine on rehearing or in a subsequent proceeding the prudence and reasonableness of those River Bend costs regard-

> ing which the evidence is inadequate to support a finding of either prudence or imprudence."
>
> (f) Commissioner Thomas in his "concurring" order criticized "the decision of the majority (the two other Commissioners) to hold in abeyance $1.453 billion of the investment in the River Bend Nuclear Plant, to allow the company any opportunity to prove construction prudence on rehearing."

The court examined the above and concluded that *this was a mere effort or attempt* by the Commission to defer or reserve adjudicating the question of the prudence or imprudence of cost in excess of $2.273 billion. The court reached this conclusion by selectively reading only portions of *findings of fact 164 and 164A* and *conclusion of law 10*, and ignoring the rest. In my opinion, this is improper. It is our duty to decide the effects of the Commission's order in light of the literal meaning of the language used by the Commission. We should not pick and choose only those portions of the record that are helpful in reaching a desired result. The court's statement that ". . . the PUC *found* that GSU had failed to prove that any expenses in excess of $2.273 bililon were prudently incurred," —— S.W.2d —— (Tex. 1990) (emphasis added) is pure fiction. A reasonable reading of the record just does not support this conclusion. On the contrary, the Commission found that it would not allow a return on the $1.453 billion *"AT THIS TIME"* and made no express or implied finding of imprudence with respect to this major portion of GSU's claim.

Our court concludes that because the Commission was not authorized to defer its ruling, its decision to do so is void, not merely voidable.[4] There are numerous decisions

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[4] The court finds *Sexton v. Mount Olivet Cemetery Association*, 720 S.W.2d 129 (Tex. App.—Austin 1986, writ ref'd n.r.e.) instructive and persuasive. In *Sexton*, the court of appeals held that

by agencies and courts which, though erroneous, are effective until set aside on appeal. In *Schieffer v. Patterson*, we said:

> No matter how erroneous its conclusion and action may have been, it was within the judicial power of the court to determine that the cause was severable and to sever the same accordingly. The order of severance is subject to being set aside on appeal, but until this is done it effectively separates the controversy into two causes. A judgment which fully adjudicates one of the several causes is appealable even though the entire controversy as it existed prior to the severance is not determined thereby.

433 S.W.2d 418, 419 (Tex. 1968) (quoting *Pierce v. Reynolds*, 329 S.W.2d 76, 78-79 (Tex. 1959)).[5] Clearly

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the Banking Commission had no power to reopen proceedings and reconsider whether the association would have approval to sell prepaid funeral plans. *Sexton* is distinguishable from the instant case because in *Sexton*, the Banking Commission attempted to exercise jurisdiction after it had made a final decision. Under those circumstances it is clear that any attempt to act after its jurisdiction expired would have been void. See *Plains Growers, Inc. v. Jordan*, 519 S.W.2d 633 (Tex. 1974). Although the Banking Commission illegally attempted to reserve the power to reopen cases, this action did not detract from the Commission's *having made a final decision*. In the instant case, the PUC expressly stated that *no decision had been reached* as to $1.453 billion in costs in excess of the amount it expressly approved as being prudent, and invited further proceedings by rehearing or new proceeding for the issue expressly reserved. The Commission attempted to make its determination final as to the $2.273 billion it found to be prudent by severing its consideration of the balance. The court now transforms this severance into a deemed finding against GSU despite the Commission's express statement that no finding had been made.

[5] In *Schieffer*, the issue of liability was improperly severed from damages. Our court held that the court of civil appeals had to take and determine the case as severed, unless and until the severance was set aside. 433 S.W.2d at 419.

a matter that has been expressly reserved from an order has not been decided, and "the res judicata effects of an action cannot preclude litigation of claims that a trial court explicitly separates or severs from that action." *Van Dyke v. Boswell, O'Toole, Davis & Pickering*, 697 S.W.2d 381, 384 (Tex. 1985).

Even though the Commission erred in deferring its decision, that is precisely what it did. Thus, the issue is not whether a public utility is entitled to a second opportunity to prove the same facts as justification for a rate increase, (they are not entitled to two bites at the same apple), but, instead, the central issue is what are the legal consequences or effects that flow from the Commission's error. The court chooses to make an independent finding that the cost overruns in excess of $2.273 billion were imprudent since the Commission did not find that they were prudent. The effect of this decision is to assess a $1.453 billion penalty (permanent disallowance) on GSU all in the name of res judicata and collateral estoppel. I do not think that this is fair[6] nor that we have the power to make this "negative finding" when the Commission expressly stated that it did not find that the costs were prudent or imprudent.[7]

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[6] All parties (including GSU) are entitled to an unequivocal decision by the tribunal empowered to make a decision. In this case, it is the Commission and not this court who is empowered by the legislature to calculate utility rates and to protect the public interest by disallowing costs and expenses that are not prudently made. See *Public Utility Comm'n v. Houston Lighting & Power*, 748 S.W.2d 439 (Tex. 1987).

[7] The court relies on *Gerst v. Goldsbury*, 434 S.W.2d 665 (Tex. 1968) for its conclusion that the failure to rule in GSU's favor is converted into a negative finding. In *Gerst* the commission's finding that there was insufficient evidence on an issue was characterized as a negative finding. However, there was no attempt to reserve the issue for latter [sic] decision. The order did not purport to be anything other than a final adjudication on all issues before the commission.

The court today reaches its result by equating an administrative proceeding to a trial and stating that if a finder of fact determines that a party failed to carry its burden of proof on an issue, adjudication should be against that party. This is the case in a regular trial setting, but it may or may not be applicable in an administrative proceeding depending on some factors that are not present in a conventional trial.

Administrative agencies perform (sometimes simultaneously) governmental functions of legislating, executing and enforcing their rules and resolving disputes arising under those rules and laws passed by the legislature. "Agencies do not always resolve disputes in the same manner as courts. Courts base decisions on the application of existing law to particular facts. Agencies, however, may use adjudication as a policy-making technique and focus as much on prospective policy goals and considerations as on the particular dispute." Note, *Collateral Estoppel Effects of Administrative Agency Determinations: Where Should Federal Courts Draw the Line?* 73 Cornell L. Rev. 817, 836 (1988). They also resolve disputes based on their own expertise in a certain area of the law, (e.g., the Railroad Commission and regulation of oil and gas), so they may resolve disputes based on their own predispositions rather than on purely neutral application of the law to the facts. Unlike judges and juries in conventional trials, administrative tribunals are charged with the responsibility of balancing and protecting public interests. See, e.g., Tex. Rev. Civ. Stat. Ann. art. 1446c, §§ 2, 54(c) (Vernon Supp. 1990). Thus, the analogy to conventional trials does not fit. The court's facile analysis will lead to confusion, has the potential for unintended consequences and will spawn litigation.

All administrative agencies are not created equally. They have differing levels of authority, review powers, and afford varying levels of procedural safeguards. It is

not always easy to determine if the administrative agency was acting in a "judicial capacity". In *State v. Thomas*, 766 S.W.2d 217, 219 (Tex. 1989), we said that ratemaking was a quasi-judicial function. In *State v. Southwestern Bell Telephone Co.*, 526 S.W.2d 526, 529-30 (Tex. 1975), we said that the fixing or revision of rates is a legislative function. Only those issues that an agency determines while acting in a judicial capacity and when the parties are given a full and fair opportunity to participate in the adjuratory process should be given preclusive effect. Thus, at the very least, we should establish limits or guidelines to the application of collateral estoppel and res judicata to adjudications by administrative agencies.

The United States Supreme Court has set forth additional requirements before it will give preclusive effect to an administrative decision. In *United States v. Utah Construction & Mining Co.*, 384 U.S. 394 (1966), the Court set forth several requirements:

> (1) the agency must have jurisdiction to resolve the issue; (2) the agency must act in a judicial capacity; (3) the agency must properly resolve the dispute before it; and (4) the parties must have an adequate opportunity to litigate.

Id. at 422. Application of collateral estoppel to administrative agency decisions in Texas should also pass the traditional test in addition to the standards articulated in *Utah Construction and Mining Co.*

Here it is apparent that the Commission did not properly resolve the dispute before it. Therefore, neither res judicata nor collateral estoppel may operate to preclude claims or issues in this case. If we take the court's decision to its logical conclusion, the effect of today's opinion will be to impart collateral estoppel and res judicata effect on all actions and *inactions* by administrative agencies. As

a matter of fundamental fairness, for the reasons expressed above, we should affirm the judgment of the court of appeals dissolving the permanent injunction.

/s/ Raul A. Gonzalez
RAUL A. GONZALEZ
Justice

OPINION DELIVERED: September 12, 1990

Justice Cook joins in this opinion.

APPENDIX B

IN THE COURT OF APPEALS
THIRD DISTRICT OF TEXAS
AT AUSTIN

No. 3-89-167-CV

PUBLIC UTILITY COMMISSION OF TEXAS, *et al.*,
Appellants

VS.

COALITION OF CITIES FOR AFFORDABLE
UTILITY RATES, *et al.*,
Appellees

From the District Court of Travis County,
250th Judicial District
No. 447, 502-A,
Honorable Harley Clark, Judge

[September 20, 1989]

Appellees, Coalition of Cities for Affordable Utility Rates and others, filed a declaratory judgment suit in the district court of Travis County pursuant to Tex. Civ. Prac. & Rem. Code Ann. §§ 37.001-37.011 (1986 & Supp. 1989). By their suit, appellees sought a declaration that appellant, Public Utility Commission of Texas, had no authority to entertain a hearing concerning the prudence *vel non* of appellant Gulf States Utilities Company's investment of $1.4 billion in the River Bend Nuclear Generating Station. Ancillary to their declaratory judgment suit, appellees sought injunctive relief prohibiting the Commission from conducting such hearing.

After hearing, the district court signed a temporary injunctive order prohibiting the Commission from going forward with its hearing. This Court dissolved the temporary injunction. *Public Utility Com'n v. Coalition of Cities, et al.*, Nos. 3-89-093-CV, 3-89-095-CV, Tex. App.—Austin, August 9, 1989 (not yet reported).

While the appeal of the temporary injunction was pending in this Court, the district court signed the final judgment permanently enjoining the Commission from conducting its hearing. It is from the final judgment that appellants have taken this appeal. We will reverse the judgment and dissolve the permanent injunction.

This appeal arose from consolidated administrative appeals to district court from the Commission's order in Docket No. 7195. In Docket No. 7195, Gulf States sought an electrical rate increase predicated upon, among other things, rate base recognition of its investment in River Bend. The appellees challenged Gulf States' prudence in determining in 1979 to go forward with the construction of River Bend. After a protracted evidentiary hearing, the Commission entered its order in Docket No. 7195 setting rates and therein recognizing Gulf States' prudence in investing some $2.273 billion in the construction of River Bend. By further provisions of its order, however, the Commission sought to defer for a later hearing the determination of the prudence of an additional $1.4 billion investment by Gulf States in River Bend. Thereafter, in March 1989, Gulf States filed with the Commission its new rate case, Docket No. 8702, in which it requested rate base recognition of the $1.4 billion in River Bend construction costs. The Commission has scheduled the matter for hearing. The district court after hearing in the declaratory judgment suit then signed the judgment and permanent injunctive order now under consideration. The district court's permanent injunction prohibits the Commission from going forward with the hearing in Docket No. 8702.

The central premise in the district court's judgment is that the Commission's order in Docket No. 7195 passed upon the "prudence issues" and that, as a result, the principles of res judicata and collateral estoppel barred the Commission from conducting the second hearing in Docket No. 8702.[1] Appellants attack the district court's conclusion.

The Latin phrase "res judicata" means that the matter has been adjudged, a thing judicially determined, or a matter settled by judgment. The principle of res judicata is an old one founded upon public policy. Its function is to expedite justice by ending litigation and preserving the sanctity of judgments. *Abbott Laboratories v. Gravis*, 470 S.W.2d 639 (Tex. 1971); *Stewart v. City of Austin*, 744 S.W.2d 682 (Tex. App. 1988, writ ref'd). An existing final judgment rendered upon the merits by a court of competent jurisdiction upon a matter within its jurisdiction is conclusive of the rights of the parties in all other actions on the points at issue and adjudicated in the first suit. *Permian Oil Co. v. Smith*, 107 S.W.2d 564 (Tex. 1937). The common law rule of res judicata as applied in Texas bars litigation of all issues connected with a cause of action or defense which, with the use of diligence, might have been tried in a former action as well as those which were actually tried. *Ogletree v. Crates*, 363 S.W.2d 431 (Tex. 1963).

Under proper circumstances, the principles of res judicta are applicable to administrative orders. *Sexton v. Mount Olivet Cemetery Ass'n*, 720 S.W.2d 129 (Tex. App. 1986, writ ref'd n.r.e.); *Al-Jazrawi v. Texas Bd. of Land Surveying*, 719 S.W.2d 670 (Tex. App. 1986, writ ref'd

---

[1] The district court overlooked the fact that res judicata and collateral estoppel are affirmative defenses which appellees should raise in due course at the Commission in Docket No. 8702. If unsuccessful at the agency level, then appellees may pursue those defenses through the ordinary administrative appeal process.

n.r.e.); *Champlin Exploration, Inc. v. Railroad Com'n*, 627 S.W.2d 250 (Tex. App. 1982, writ ref'd n.r.e.).

Resolution of the present appeal hinges upon analysis of the Commission's order. If, indeed, the Commission deferred for later determination the prudence of the $1.4 billion costs of construction of River Bend, then the principles of res judicata are inapplicable. On the other hand, if there was no deferral of that matter, then the order in Docket No. 7195 may be asserted as a bar in the Docket No. 8702 proceeding.

The Commission incorporated its findings of fact and conclusions of law into its order. In that connection, the Commission adopted its examiners' report in large part but rejected and modified it in other respects. Pertinent to the problem in this appeal, the examiners recommended the adoption of finding of fact no. 164 that nine percent of the total costs of the River Bend project be excluded as imprudent. The examiners also recommended the adoption of conclusion of law no. 10 that the principle of res judicata precludes any further litigation of the River Bend prudence issues. The Commission rejected the above described proposed finding of fact and conclusion of law and, instead, filed the following findings of fact nos. 164 and 164A and conclusion of law no. 10:

> 164. The preponderance of the evidence in this case establishes that $2.273 billion of River Bend capital costs were prudently and reasonably incurred. The evidence is inadequate to support a finding of either prudence or imprudence with regard to construction costs in excess of $2.273 billion, with the exception of the costs related to the 50-month schedule and TDI, addressed in Findings of Fact Nos. 133 and 145.
>
> 164A. GSU's share of all River Bend capital costs in excess of $2.273 billion should be excluded from plant in service *at this time* for lack of sufficient

> evidence as to the prudence and reasonableness of those costs. The amount which should be included in plant in service, given GSU's 70 percent share of the plant, is $1.5911 billion [emphasis added].
>
> 10. Pursuant to PURA Sections 16(a), 38, 39(a), and 41, the Commission may reexamine on rehearing or in a subsequent proceeding the prudence and reasonableness of those River Bend construction costs regarding which the evidence is inadequate to support a finding of either prudence or imprudence.

A judgment is construed like other written instruments. *Permian Oil Co. v. Smith*, 107 S.W.2d 564 (Tex. 1937). If a judgment is unambiguous, the court's duty is to declare its effect in light of the literal meaning of the language employed. *Adams v. Adams*, 214 S.W.2d 856 (Tex. Civ. App. 1948, writ ref'd n.r.e.). There is no reason that the same rules should not be applicable to agency orders.

From an examination of the findings and conclusions and particularly the language of findings of fact nos. 164 and 164A, and conclusion of law no. 10, this Court concludes that the Commission, in exercising its discretion in the control and management of its docket, resolved to postpone for a later determination the prudence *vel non* of Gulf States' investment of the additional $1.4 billion in the River Bend project.

That the Commission postponed its decision on the additional $1.4 billion investment was recognized by Commissioner Thomas in his "concurring" order, "I respectfully dissent from the decision of the majority to hold in abeyance $1.453 billion of the investment in the River Bend Nuclear Plan, to allow the company an opportunity to prove construction prudence on rehearing. In my opinion, the record was sufficiently developed to reach a final conclusion."

The district court further determined that although the Commission may not have ruled directly on the prudence issues of the $1.4 billion investment, it must have considered those issues in arriving at the findings and conclusions it made. The district court asserted in addition that even if the Commission did not consider those issues, Gulf States "had ample opportunity to have the issue considered, litigated and decided." In either event, opined the district court, the rule of res judicata barred subsequent assertion of the issue in Docket No. 8702.

This Court does not agree. We, of course, recognize and acknowledge the rule of res judicata that bars litigation of all issues connected with a cause of action or defense which, with the use of diligence, might have been tried in a former action as well as those which were actually tried. *Ogletree*, 363 S.W.2d 431. The rule of res judicata, however, has no application here. In its order, the Commission explicitly postponed the determination of one of Gulf States' major claims. The Commission's action in this respect may be compared to that of the trial court in severing a claim and proceeding separately with it. Tex. R. Civ. P. Ann. 41 (Supp. 1989). No one would countenance a suggestion that res judicata bars litigation of the severed claim.

Finally, in support of its order, the district court noted in finding twelve that the utility complained in its administrative appeal of Docket No. 7195 of the Commission's failure to recognize the $1.4 billion sum as a prudent investment. As a result, concluded the district court, the Commission was without authority to proceed with its hearing in Docket No. 8702 because "that issue is pending before [the district court]."

As already discussed, the Commission in Docket No. 7195 made no final determination with respect to the prudence of the $1.4 billion investment. Rather, the Commission explicitly determined not to decide the prudence

issue but instead to require additional proof in a further hearing.

To avoid possible waiver, the utility was required to complain in its administrative appeal of the Commission's refusal to go forward and recognize the $1.4 billion sum as a prudent investment. The utility's preservation of error in the administrative appeal, however, does not somehow deprive the agency of the power to proceed with a determination of the prudence of that investment in Docket No. 8702.

The judgment is reversed and the permanent injunction is dissolved.

/s/ Bob Shannon
BOB SHANNON
Chief Justice

[Before Chief Justice Shannon, Justices Carroll and Aboussie]

Reversed and Permanent Injunction Dissolved

Filed: September 20, 1989

[Publish]

APPENDIX C

IN THE DISTRICT COURT
OF TRAVIS COUNTY, TEXAS
250TH JUDICIAL DISTRICT

No. 447,502-A

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES, *et al.*,
Plaintiffs

v.

PUBLIC UTILITY COMMISSION OF TEXAS and GULF STATES UTILITY COMPANY,
Defendants

FINAL JUDGMENT

[July 10, 1989]

On the 10th day of July, 1989, came on to be heard Plaintiff's application for declaratory judgment and for permanent injunction to prevent the Public Utility Commission of Texas (Commission) from the relitigation of the prudence of the costs to construct the River Bend Nuclear Power Project in Docket No. 8702, styled Application of Gulf States Utilities Company for Authority to Increase Rates.

After hearing the arguments of counsel, the evidence addressed herein, and reviewing the entire record before this court, including the pleadings, briefs, exhibits[,] statements of fact and arguments of counsel in Cause No. 447,502 the court concludes that Plaintiffs are entitled to a permanent injunction.

The court finds and concludes as follows:

1. This court has jurisdiction to hear Plaintiffs' application for permanent injunction although an appeal is pending from this court's previous order granting temporary injunction; jurisdiction remains in this court to try the case on the merits.

2. To permit the Commission to consider the prudence of the cost to construct the River Bend Nuclear Power Project in Docket No. 8702 would permit the relitigation of the reasonableness and prudence of the cost to construct River Bend, heretofore litigated in Docket No. 7195.

3. Although the Commission has broad powers given it in PURA, the more specific provisions of the Administrative Procedure and Texas Register Act regarding the procedures to be followed and the rights of the parties in contested cases control and limit the Commission's power and authority in these cases.

4. The doctrines of res judicata and collateral estoppel apply to administrative agencies.

5. The Commission directly ruled on the prudence issues in its finding and conclusions.

6. Even if the Commission's findings and conclusions can be interpreted as lacking a direct ruling on the prudence issues, the Commission must have considered the issue to arrive at the findings and conclusions it actually made.

7. Even if the Commission's findings and conclusions can be interpreted as not requiring consideration of the issue, Gulf States Utilities had ample opportunity to have the issue considered, litigated and decided.

8. Any of the three scenarios mentioned immediately above are sufficient to invoke the doctrines' prohibition of subsequent relitigation.

9. The Commission is without authority to permit or sponsor additional litigation or consideration of the issue.

10. The Court announced its decision to the parties by letter, dated May 5, 1989. Thereafter, the Commission informed the Court that it voted to allow the scheduling order setting a hearing and establishing procedures for the relitigation of the River Bend prudence issue in Docket No. 8702 to stand. The Commission's order is attached as Exhibit A. In Docket No. 8702, Gulf States Utilities Company seeks to litigate again the prudence of its investment in the River Bend project that was litigated in Docket No. 7195.

11. The Court finds that such action will cause irreparable harm and injury to plaintiffs, in that it will cause plaintiffs to be subject to re-litigation of the prudence issue that the Court has concluded is precluded from further litigation by the doctrines of res judicata and collateral estoppel.

12. The court further finds that Defendant Gulf States Utilities has appealed, as part of Cause No. 447,502 pending before this court, the Commission's failure to find that the cost to construct River Bend in excess of $2.273 billion was prudently incurred.

13. Apart from and irrespective of the preclusion of relitigation of the prudence issue by the doctrines of res judicata and collateral estoppel, the court finds that as a result of the administrative appeal now pending before this court as cause No. 447,502, the Commission has lost the authority to relitigate the prudence of the cost to construct River Bend while that issue is pending before this court on appeal.

IT IS THEREFORE, ORDERED, ADJUDGED, AND DECREED that a Permanent Injunction be entered herein; that the Commission be permanently enjoined from holding hearings on or reconsidering the prudence

of the cost to construct River Bend except to the extent such proceedings are permitted as part of a remand from the administrative appeal of Docket No. 7195.

SIGNED AND ENTERED THIS 10TH DAY OF JULY, 1989.

/s/ Harley Clark
JUDGE HARLEY CLARK

EXHIBIT A

PUBLIC UTILITY COMMISSION OF TEXAS

Docket No. 8702

APPLICATION OF GULF STATES UTILITIES COMPANY FOR AUTHORITY TO CHANGE RATES

ORDER DENYING APPEALS

In open meeting at its offices in Austin, Texas, the Public Utility Commission of Texas considered the appeals of the Cities and the Office of Public Utility Counsel of Examiners' Orders No. 3, No. 7 and No. 9. The appeals are DENIED and Examiners' Orders No. 3, No. 7 and No. 9 are AFFIRMED.

The examiners are instructed to proceed with consideration of nuclear/prudence issues related to the River Bend Nuclear Power Station as established in Examiners' Orders No. 3, 7 and 9 pending any superseding order of the Commission.

SIGNED AT AUSTIN, TEXAS on the 12th day of May 1989.

SIGNED Marta Greytok
MARTA GREYTOK

SIGNED William B. Cassin
WILLIAM B. CASSIN

I respectfully dissent. The Cities and OPUC's appeals should be granted. Once we lost jurisdiction over Docket No. 7195, the doctrine of res judicata applied to the relitigation of the River Bend prudence issues. I so stated at the time the Commission allowed the Motions for Rehearing to be overruled by operation of law. Those issues were fully litigated in that docket, and the company simply failed to meet its burden of proof for any costs in excess of those granted. I agree completely with Judge Clark's letter ruling.

The majority's reasoning in support of upholding the Examiner's Order as stated in the record is fallacious. We made no disallowance for excess capacity. We did not allow *only* a portion of the plant in rate base. The total plant was included in rate base at the cost the company showed to have been prudently incurred. Had the Commission wanted to hear further evidence regarding these issues it could have done so by granting the Motions for Rehearing. *City of El Paso v. PUC*, 609 S.W.2d 574 (Tex. Civ. App.—Austin, 1980, writ ref'd n.r.e.). Having refused to do so, the mere statement of a conclusion of law as a finding of fact does not and should not prevent the doctrine of res judicata from applying.

SIGNED AT AUSTIN, TEXAS on the 12th day of May, 1989.

SIGNED Jo Campbell
JO CAMPBELL

ATTEST:

/s/ Phillip A. Holder
PHILLIP A. HOLDER
Secretary of the Commission

APPENDIX D

ORDERS OF THE SUPREME COURT OF TEXAS

Pronounced November 28, 1990

ORDERS ON MOTIONS

THE FOLLOWING MOTIONS FOR REHEARING OF CAUSES ARE OVERRULED

C-9287, COALITION OF CITIES FOR AFFORDABLE UTILITY RATES ET AL. v. PUBLIC UTILITY COMMISSION OF TEXAS ET AL.; from TRAVIS County; 3rd district (03-89-00167-CV, 777 SW2d 814, 09-20-89)
2 motions, as corrected

APPENDIX E

IN THE COURT OF APPEALS

[Third District of Texas, at Austin]

OCTOBER 11, 1989

CIVIL MOTIONS SUBMITTED AND OVERRULED:

Motion	*Cause*	
CV-23,540	89-167-CV	Public Utility Commission of Texas, et al. v. Coalition of Cities for Affordable Utility Rates, et al. Appeal from 250th District Court of Travis County Appellees' Motion for Rehearing (Coalition of Cities, et al.)
CV-23,641	89-167-CV	Public Utility Commission of Texas, et al. v. Coalition of Cities for Affordable Utility Rates, et al. Appeal from 250th District Court of Travis County Appellees' Motion for Rehearing (Cities of Bridge City, et al.)
CV-23,657	89-167-CV	Public Utility Commission of Texas, et al. v. Coalition of Cities for Affordable Utility Rates, et al. Appeal from 250th District Court of Travis County Appellee's Motion for Rehearing (OPUC)

APPENDIX F

[In the Supreme Court]

THE STATE OF TEXAS

[DECEMBER 27, 1990]

To the District Court of Travis County, Greetings:

Before our Supreme Court on the 12th day of September A.D. 1990, the Cause, upon writ of error, to revise or reverse your Judgment between

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES *et al.*

vs.

PUBLIC UTILITY COMMISSION OF TEXAS *et al.*

No. *C-9287* in the Supreme Court of Texas

No. *447,502-A* in the *250th* District Court of *Travis* County, Texas, was determined; and therein our said Supreme Court entered its judgment or order in these words:

"THE SUPREME COURT OF TEXAS, having heard this cause on writ of error to the Court of Appeals for the Third District, and having considered the appellate record and the argument of counsel, is of the opinion that the judgment of the court of appeals should be reversed.

"IT IS THEREFORE ORDERED, in accordance with the Court's opinion, that:

1) The judgment of the court of appeals is reversed;

2) The judgment of the trial court is affirmed;

3) Coalition of Cities for Affordable Utility Rates et al. shall recover from the Public Utility Com-

mission of Texas et al., and surety, National Surety Corporation, which shall pay, the costs in this Court and in the court of appeals.

"A copy of this judgment and of the Court's opinion is certified to the court of appeals and to the District Court of Travis County, Texas, for observance."

Wherefore we command you to observe the order of our said Supreme Court in this behalf, and in all things to have recognized, obeyed, and executed.

Witness the Honorable **Thomas R. Phillips**, Chief Justice of our said Supreme Court, with the seal thereof annexed, at the City of Austin, this the 27th day of December A.D. 1990

JOHN T. ADAMS, Clerk

By _____
COURTLAND CROCKER
Deputy

APPENDIX G

PUBLIC UTILITY COMMISSION OF TEXAS

Docket Nos. 7195 and 6755

APPLICATION OF GULF STATES UTILITIES COMPANY FOR AUTHORITY TO CHANGE RATES

INQUIRY OF THE PUBLIC UTILITY COMMISSION OF TEXAS INTO THE PRUDENCE AND EFFICIENCY OF THE PLANNING AND MANAGEMENT OF THE RIVER BEND NUCLEAR GENERATING STATION

ORDER

[May 16, 1988]

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that after statutory notice was provided, the application in this case was processed in accordance with applicable rules and statutes by examiners who filed a report containing findings of fact and conclusions of law. The examiners' report is ADOPTED and incorporated by reference into this Order with the following modifications:

A. For the reasons expressed in public meeting, the findings of fact and conclusions of law attached to this Order as Attachment 1 are ADOPTED in lieu of the proposed findings and conclusions in the examiners' report. As a result, the examiners' proposed Findings of Fact Nos. 128, 151, 153-61, 179-90, 192, 233, and 248 and proposed Conclusions of Law Nos. 21-23 have been deleted from the attached findings and conclusions; proposed

Findings of Fact Nos. 8, 163, 164, 166, 168, 169, 170, 191, 198, 202, 206, 209, 212, 214, 218, 225, 229, 234, 236, 237, 239, 240, 250, 255, 256, 261, 278, 288, 293, 302, 306, and 307 and Conclusions of Law Nos. 10, 18, 19, and 20 have been modified; and Findings of Fact Nos. 8A-B, 164A, 202A-B, 214A, and 250A-L and Conclusion of Law No. 18A have been added to those proposed by the examiners.

B. Those portions of the discussion in the examiners' report that support or recommend findings of fact or conclusions of law contrary to those adopted by this Order are NOT ADOPTED.

Schedules I-VIII and Attachments 1 and 2 are attached to and incorporated into, this Order. The Commission further issues the following orders:

1. The application of Gulf States Utilities Company (GSU or the Company) is GRANTED in part and DENIED in part, as reflected in the terms of this Order and the attached findings of fact and conclusions of law.

2. The Company shall recalculate its cost of service and design rates in accordance with the terms of this Order. No later than 10 days after the date of this Order, the Company shall file with the Commission five sets of a proposed tariff necessary for the Company to implement the directives of this Order and to generate the revenues prescribed in this Order; the Company shall serve one copy of the proposed tariff upon each party of record. No later than 10 days after the filing of the proposed tariff by the Company, the parties shall file any objections to the proposed tariff, and the general counsel shall file the staff's comments recommending approval, rejection, or modification of individual sheets of the proposed tariff. No later than 15 days after the

filing of the proposed tariff by the Company, all parties and the general counsel shall file any responses to the comments and objections of the other parties. The Hearings Division shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter, based upon the materials submitted to the Commission under the foregoing procedure. In the absence of written notification by the Hearings Division, the proposed tariff sheets will be deemed approved and will become effective on the twenty-first day after the date of filing. If any sheets are modified or rejected, the Company shall file proposed revisions of those sheets in accordance with the Hearings Division letter no later than 10 days after the date of that letter, with the review procedures set out above again to apply. Copies of all documents and Hearings Division letters related to the review procedure must be served on all parties of record and the general counsel and filed with the Commission filing clerk before 4:00 p.m. on the last permissible date.

3. The Company shall charge the approved rates for service in all areas in which the Commission has exclusive original jurisdiction and in those municipalities for which the Commission has appellate jurisdiction in this case. The municipalities are listed in Section I of the examiners' report. The rates may be charged only for service rendered after the tariff approval date. Should the tariff approval date fall within the Company's billing period, the Company shall prorate each customer's bill to reflect that customer's customer charge, demand charge, and charge for daily energy consumption at the appropriate new rates.

4. GSU shall file its future rate filing packages on a "total electric" basis.

5. GSU shall place the amounts identified and approved by the Commission as decommissioning ex-

pense in a trust fund qualified for tax-free treatment under Internal Revenue Service regulations. The trust fund is to be irrevocable, and the amounts placed into the trust fund may not be used for any purpose other than the decommissioning of the River Bend Nuclear Generating Station.

6. At the end of each calendar quarter, GSU shall file with the Commission a report of its efforts to divide itself into two companies separately providing utility service in Texas and in Louisiana.

7. All motions, applications, requests for adoption of findings of fact and conclusions of law, and general or specific requests for relief not expressly granted by the Commission or by examiners' order are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on the 16th day of May 1988.

PUBLIC UTILITY
COMMISSION OF TEXAS

Signed: Marta Greytok
MARTA GREYTOK

I concur with the Order of the Commission except as set forth below:

1. I respectfully dissent from the decision of the majority to hold in abeyance $1.453 billion of the investment in the River Bend Nuclear Plant, to allow the Company an opportunity to prove construction prudence on rehearing. In my opinion, the record was sufficiently developed to reach a final conclusion. I would have disallowed $459,737,768 based upon the regression analysis presented in Dr. Perl's supplemental testimony including the northeast variable. That analysis found a predicted River Bend cost of $3,125 per kW compared to an actual cost of $3,681 per kW, resulting in an excess of $556 per kW or 15.1% of the investment. In addition, I would have held in inventory 798 MW at an aver-

age system cost of $621 per kW. Based upon the testimony of Cities' witness Pous, I believe the 798 MW should be held in inventory because it did not meet the test of being used and useful. This would result in a reduction to rate base of an additional $495,558,000. GSU would be allowed to recover depreciation and operations and maintenance charges on the inventoried capacity and could bring it back into rate base at such time it was used and useful. Taken together, I believe the evidence in the record supports a reduction to rate base of $955,295,768. Even though a reduction of this size is a harsh result the Company would benefit from a resolution of uncertainty, one of its major impediments to regaining financial health.

2. I do not believe the return on equity of 13% allowed by the majority is a realistic measure of investor demands for a company in as difficult a financial situation as GSU. In addition, the large amount of the plant held in abeyance for an additional proceeding will further increase the rate investors require to risk their money on the Company. Instead, I would have allowed a return on equity of 14.25% as compared to the examiners' recommended rate of 15.25%, with clear indication that the return on equity would drop as financial indicators improve.

3. I respectfully dissent from the majority in their decision to remove from rate base the units proposed for the Nelson Steam Venture (Docket No. 7147). It is unfair for the Commission to prohibit the transfer of Nelson Units 1 and 2 of rate base by the decision to disallow periodic energy payments above avoided cost, an integral part of the negotiated contract, and then to punish the Company for having the units as excess capacity. While I agree with a broad application of the used and useful criteria, its hindsight application in this situation is not proper.

4. I agree with the majority in most aspects on the decision concerning regulatory and rate case expenses, but would respectfully dissent on the following four specific points:

   a. I do not believe a rate case expense surcharge is useful. It unnecessarily highlights a relatively small expense of approximately $2.8 million per year, when there are more important expenses to highlight if the concern is consumer awareness.

   b. I dissent from the open-ended invitation given by the majority as part of the rate case expense motion to the groups of city intervenors to file amicus curiae briefs in Cause C-5705 (PUC v. HL&P) before the Supreme Court, and to have those expenses paid by the Company and in turn ratepayers. The recovery of expenses for this purpose had not been requested by the Cities at the time of this motion. Specific numbers were presented on the last day of hearings and I am in agreement that the specific expenses are reasonable given the encouragement by the majority earlier in the case. It is this earlier decision from which I dissent.

   c. The disallowance by the majority of the Company's ability to recover expenses already paid on behalf of the Public Parties Committee is a breach of faith with the agreement that established the Committee. The Company reserved the right to review expenses but this disallowance based on the perception by the majority of duplicative testimony among Public Parties Committee participants is founded on hindsight and punishes the Company, which is only tangentially at fault if duplication in fact existed. I therefore dissent and would have allowed recovery of the full amount expended by the Company on behalf of the Public Parties Committee.

5. The disallowance by the majority of certain energy conservation and load management expenses is not in the long-term benefit of GSU customers or the Company. While the amounts are relatively small, the negative message this disallowance sends to GSU and to other Texas companies at a time when they should be increasing their efforts to shape loads for efficiency and increasing conservation assistance to individual customers, is regretful. I therefore dissent and would have allowed the amounts requested by the Company.

Signed: Dennis L. Thomas
DENNIS L. THOMAS

I concur with the Order of the Commission except as set forth below:

I respectfully dissent from Finding of Fact 250H, that testimony of local counsel established by a preponderance of the evidence that the following cities should be reimbursed for reasonable and necessary rate case expenses; Bridge City, $8,679; Groves, $16,172, Nederland, $29,472; Port Arthur, $2,606; Port Neches, $23,071; Rose City, $7,289; and Vidor and Bevil Oaks, $14,610.

Section 24(a) of PURA provides:

> The governing body of any municipality participating in or conducting ratemaking proceedings shall have the right to select and engage rate consultants, accountants, auditors, attorneys, engineers, or any combination thereof, to conduct investigations, present evidence, advise and represent the governing body, and assist with the litigation in public utility ratemaking proceedings before the governing body, any regulatory authority, or in court. The public utility engaged in such proceedings shall be required to reimburse the governing body for the reasonable

costs of such services to the extent found *reasonable* by the applicable regulatory authority.

All of these cities also participated in the hiring of the firm of Butler and Casstevens to represent their interests before the Commission. They also had the benefit of representation by Diversified Utility Consultants and Parnell, Kerr and Forester to provide representation on a broad range of issues. The Commission found that the $736,946.18 paid to these three firms was reasonable and inured to the benefit of all the ratepayers of Gulf States Utilities. I concurred in that decision. In each instance, these firms appeared before the Commission and provided representation or testimony which benefitted all ratepayers.

However, there must be a limit as to how much expense a city council can impose upon the ratepayers under Section 24(a). For those expenses to be reasonable and passed on to the entire set of ratepayers they should satisfy at least two conditions. First, the expense should reflect a benefit to all ratepayers, not just to those of the city incurring the obligation. The testimony sponsored by Mr. Butler and his participating cities met that condition.

Second, the efforts should not be duplicative of the efforts of others representing similar interests. The record showed that Mr. Butler and his consultants, as well as Mr. Boyle and his consultants representing a separate group of cities, divided issues so as not to duplicate services.

With respect to Finding of Fact 250H, I don't believe PURA contemplates funding a city attorney rate case division on the backs of the ratepayers in each city served by a utility. I find it curious that Mr. Boyle was able to provide representation to his client cities without saddling the ratepayers with duplicative legal expense, but that a number of the cities represented by Mr. Butler incurred significant local expenses that in no way contributed to the record in this docket or assisted the Commission in rendering a decision.

In fact, there is considerable evidence in the record that indicates that some of the attorneys representing the same cities represented by Mr. Butler billed primarily for "receipt and review" of the mass of documents filed in Austin in this rate case. By having themselves placed on the service list as intervening attorneys, they literally found a way to turn PURA into a money printing machine at the expense of the ratepayers of Gulf States Utilities. The majority position of the Commission in ratifying this practice is an invitation to cities and attorneys to further burden the ratepayers of all utilities in this state with almost unlimited rate case expense.

The record shows that these small cities by action of their city councils incurred rate case costs as high as $24.88 per meter customer in their cities. That amounts to a little over $2 per month per cusotmer when spread over a customer base for a year. That level of expense in rate participation is *per se* unreasonable.

Even if one accepts the argument that a city council must keep itself informed about the progress of a rate case, that is a function that should be borne by the city making the decision to incur the obligation to pay a legal fee. Keeping a city council informed and participating in a rate case are two entirely different matters. There are far more efficient means than paying an attorney in every city $125 an hour for "receiving and reviewing" the hundreds of thousands of pieces of paper filed in a typical rate case. It would be much more efficient and probably satisfy any information need, if Mr. Butler provided each client city government with a monthly summary of a few pages. The ratepaypers of Beaumont, Navasota and other cities in the GSU service area should not have to pay for the actions of the cities of Bridge City, Groves, Nederland, Port Arthur, Port Neches, Rose City, Vidor, and Bevil Oaks when they retain local attorneys to keep them informed. This is what the majority has ordered, and I cannot in good conscience join my

fellow commissioners in ordering the other residents of the Gulf States Utilities service area to pay $101,898 of attorney's fees that should be borne by the city governments that incurred them.

I also respectfully dissent from the Commission's decisions regarding the flow-through of excess deferred taxes. In my opinion, as I stated in open meeting on March 29, 1988, the flow-through of excess deferred taxes due to the accounting order should go to ratepayers rather than to shareholders. In addition, I dissent from the majority's decisions to flow-through the remainder of non-depreciation-related excess deferred taxes over a three-year period. In the interest of fairness to the company's ratepayers, because of the possibility that those assets might be sold, I would have those taxes flowed through immediately.

Signed: Jo Campbell
JO CAMPBELL

ATTEST:

/s/ Phillip A. Holder
PHILLIP A. HOLDER
Secretary of the Commission

ATTACHMENT 1

Findings of Fact and Conclusions of Law

A. *Findings of Fact*

1. On November 18, 1986, GSU filed an application to increase its rates within the unincorporated areas in which it serves and in those incorporated areas which have ceded jurisdiction to the Commission.

2. All Texas customers and classes of customers over which the Commission exercises original rate jurisdiction would be affected by GSU's proposed changes.

3. By examiners' order dated November 19, 1986, operation of the proposed rate schedules was suspended until May 22, 1987, or until a superseding order is issued.

4. GSU filed publishers' affidavits affirming that it has published a statement of intent in a conspicuous form and placed once each week for four consecutive weeks before the effective date of the proposed changes in newspapers of general circulation in each Texas county in which it serves.

5. GSU filed affidavits affirming that it has individually notified affected municipalities and its customers of the proposed rate changes.

6. GSU has appealed the ratemaking ordinances of the following municipalities that have retained original ratemaking jurisdiction, and the appeals have been consolidated into this case: Anahuac, Beaumont, Bremond, Bridge City, Bevil Oaks, Cleveland, Chester, Corrigan, Colmesneil, Crystal Beach, Cut-N-Shoot, Conroe, China, Devers, Groves, Huntsville, Houston, Kountze, Lumberton, Madisonville, Montgomery, Nederland, Nome, New Waverly, Normangee, Orange, Panorama Village, Pine Forest, Pinehurst, Port Neches, Port Arthur, Roman Forest, Rose Hill Acres, Rose City, Shenandoah, Shep-

herd, Sour Lake, Silsbee, Somerville, Trinity, Vidor, West Orange, Willis, Woodloch and Woodville.

7. GSU's quality of service and handling of customer complaints are adequate.

8. GSU's conservation efforts are sufficient to justify a zero adjustment to the company's return on invested capital.

8A. GSU's heat pump (comfort conditioning) and water heater rebate programs, and its Good Cents residential rider, promote marketing rather than conservation goals.

8B. GSU should not recover from its ratepayer the expenses related to its heat pump (comfort conditioning) and water heater rebate programs and its Good Cents residential rider.

9. River Bend is a BWR located near a bend in the Mississippi River just south of Saint Francisville, Louisiana, and about 28 miles north of Baton Rouge.

10. River Bend has a nominal generating capacity of 940 MW and a net rating of 934 MW.

11. GSU owns a 70 percent (658 MW) share of River Bend and Cajun Electric Power Cooperative (CEPCO) owns a 30 percent share.

12. Under a buyback agreement first signed in 1979 and modified in 1986, GSU is obligated to buy 70 percent of CEPCO's share of River Bend power the first year of the plant's operation, 56 percent the second year 42 percent the third year, 28 percent the fourth year, 19 percent the fifth year and none in subsequent years. The cost of the the buyback is based in part upon the capital cost of River Bend.

13. GSU first announced plans to build River Bend in August 1971. At that time it envisioned building two nuclear generating units at the River Bend site and two at a site in Texas known as Blue Hills.

14. GSU received a Limited Work Authorization for River Bend in September 1975. In 1977, site preparation neared completion and preparation for structural construction began. The NRC issued construction permits in March 1977 for River Bend units 1 and 2.

15. During 1977, GSU reassessed its planning objectives. Reduced load growth and the desire to maintain high financial indicators prompted GSU to curtail its construction budget and stop work on River Bend.

16. On August 1, 1978, GSU's top management and some of its directors met and reached a tentative decision to resume construction on River Bend 1, decouple and continue to defer River Bend 2, and cancel the Blue Hills units. The decision to resume construction of River Bend 1 was endorsed by the Board of Directors in February 1979. River Bend 2 was ultimately cancelled in January 1984.

17. In December 1978, after evaluating proposals from four companies, GSU chose to retain Stone and Webster Engineering Corporation (S&W) as constructor for River Bend.

18. S&W, which also remained as architect-engineer, committed to a River Bend construction schedule which would employ the Nuclear Power Construction Stabilization Agreement (NPCSA) and rolling four-ten work shifts to complete the construction of the plant, from the first concrete pour to the loading of fuel, in 50 months.

19. Actual construction of River Bend I resumed in August 1979 with the placement of rebar for the concrete basemat. In September 1979 the first concrete was poured and S&W provided GSU with a definitive cost estimate (DCE) that the plant would cost a total of $1.729 billion, including AFUDC.

20. In October 1981, GSU extended the construction of River Bend from 50 months to 68 months. That estimate

was later increased to 72 months. Fuel loading commenced in August 1985.

21. River Bend entered commercial operation on June 16, 1986.

22. The total capital cost of River Bend, including AFUDC, is approximately $4.5 billion.

23. River Bend's cost per kW is nearly $4,800, making it the fourth or fifth most expensive nuclear plant built in this country on a per-kW basis.

24. GSU's share of River Bend's capital cost at the end of the test year was $3,044,620,982.

25. If GSU were seeking to recover a return on its entire end-of-test-year share of River Bend in this proceeding using traditional ratemaking it would be seeking a first-year Texas retail rate increase of $359.9 million.

26. The driving forces behind the decision to restart River Bend were the resurgence in load growth GSU experienced in 1977 and 1978 and its projected future growth of approximately six percent annually.

27. GSU's annual peak load growth, which had ranged from two to four percent during the period 1974 through 1976, increased to approximately 12 percent in 1977 and 10 percent in 1978.

28. Adding to GSU's capacity needs was the passage in late 1978 of the federal Industrial Power Plant and Fuel Use Act (Fuel Use Act) which mandated that utilities be weaned completely from gas-fired base load generation by 1990. At that time, GSU was almost completely gas-fired.

29. GSU's annual peak load growth had exceeded five percent in every year except 1953, 1974, 1975 and 1976 at the time the River Bend restart decision was made.

30. GSU's load forecasting was flawed in its failure to account for the effects of price elasticity.

31. Projected load growth of three to four percent would have been appropriate in late 1978 and early 1979.

32. GSU could not have projected the disastrous slump in its service area's economy in the early 1980's.

33. GSU's predicted load growth was consistent with its historical pattern and with the projections of neighboring utilities.

34. GSU legitimately foresaw a need for significant new generating capacity due to projected load growth and the Fuel Use Act.

35. Because of its high capital cost GSU would have abandoned River Bend in 1978-79 in favor of another form of generation if not for the approximately $400 million in sunken and cancellation costs involved in that course of action.

36. The GSU officials present at the August 1, 1978, River Bend meeting expressed serious concern about the impact of a River Bend related write-off on the company's shareholders and on the company's ability to finance other necessary construction.

37. Less than half of total sunken and cancellation costs in 1979 would have been recovered from tax savings.

38. The potential write-off of River Bend in 1979 would have been the largest theretofore experienced for a nuclear project.

39. GSU's concern over the potential impact of the write-off of a portion of River Bend costs was not unfounded, even though GSU did not have a specific write-off number in mind above which its financial ability would be impaired.

40. The mere deferral of River Bend in 1979 would not have triggered a write-off.

41. GSU did not seriously consider continued deferral of River Bend in 1978-79.

42. In the face of load growth, the legitimate need for additional capacity, and escalating nuclear costs, GSU was not imprudent in deciding to either build or cancel River Bend in 1978-79.

43. In 1978-79, management did not know exactly how it would go about financing the completion of River Bend, particularly without participation by other utilities or significant rate relief from Louisiana.

44. The fact that GSU was not sure how it would finance River Bend does not mean that GSU thought the plant would bring it to the brink of financial disaster.

45. GSU's chief financial officer informed management in August 1978 that River Bend could be financed.

46. GSU was not imprudent in expecting some rate relief during the construction of River Bend, especially in Texas at that time.

47. In 1978, GSU could reasonably calculate $350 million in additional first mortgage bond issuance capacity above the $1.3 billion plant estimate used in the 1978 Restart Study. That amount did not include participation or other sources of financing.

48. GSU took reasonable steps to ensure that adequate financing was available for River Bend.

49. CEPCO began negotiating for a share of River Bend as early as 1974 or 1975 and had expressed continuing interest since that time. GSU and CEPCO reached a handshake agreement on participation in January 1979 and a signed agreement in August of that year. All problems had generally been worked out by February 1979.

50. GSU had no reason to expect difficulties in receiving REA approval of CEPCO's participation in River Bend.

51. GSU was reasonable in its belief that participation by CEPCO in River Bend was forthcoming in 1978-79.

52. Louisiana's December 1978 rate decision, granting a $22.8 million increase, was unexpected and improved GSU's financial prospects.

53. It would have been unreasonable for GSU to have placed too much faith in continued rate relief in Louisiana.

54. GSU's 1978 Restart Study, while giving GSU a rough idea of its financing capacity, was deficient. The study used an unreasonably low capital cost figure and did not model the financial consequences of inadequate rate relief.

55. In the 1977 "Planning For Its Growth" report, GSU's Strategic Planning Committee advocated that the company sacrifice its commitment to reliable service in order to approve its earnings per share and interest coverage ratios, achieve an "AA" bond rating, and increase its dividends.

56. For GSU to have continued pursuing the 1977 study's goals in 1978-79, in light of the perceived need for new capacity, would have been very irresponsible.

57. None of the studies and analyses presented in this docket even remotely suggest that, given 30 percent participation, GSU would have courted financial disaster from financing total River Bend costs as high as $2.6 billion.

58. Given CEPCO's participation, GSU could have financed River Bend readily at any cost level reasonably expected in 1979.

59. GSU did believe that River Bend would diversify its fuel mix and that it would be cheaper than coal-fired generation over the life of the plant, but those factors did not weigh heavily in the deliberations over the decision to restart the plant.

60. After the August 1, 1978, meeting GSU continued, without success, to attempt to sell River Bend.

61. The tentative decision made at the August 1, 1978, meeting was to build River Bend as fast as possible and

thus reduce the financial burden from construction as much as possible.

62. In late 1978 and early 1979, GSU had sufficient information to reach a decision and should have reasonably expected River Bend to cost somewhat less than $1.7 billion, which was the high end of the estimate presented to the Board in February 1979.

63. GSU was not imprudent in making the restart decision before ordering preparation of the DCE.

64. The September 1979 DCE was prepared according to industry and S&W practice by breaking down the job into its various components and applying effective unit man-hour rates. The process was thorough and the rates used realistic.

65. GSU actively monitored S&W's preparation of the DCE and had reason to believe that S&W's forecast was accurate and fairly represented the scope of work to be performed.

66. GSU asked S&W a number of questions concerning the scope of work to be covered by the DCE, escalation, man hours levels, headquarters cost, and probable levels of confidence in various aspects of the DCE.

67. GSU was actively involved in monitoring and questioning the assumptions underlying the DCE. There was a continual interchange of queries and information between Mr. Schultz of S&W and Dr. Weigand of GSU.

68. GSU was prudent in its control and monitoring of S&W's preparation of the DCE.

69. The computerized S&W Engineering Management System (EMS) was seriously flawed in 1979. The system was not prepared for the 50-month schedule.

70. More GSU engineers at S&W's headquarters or an earlier audit of EMS would not necessarily have significantly improved the DCE.

71. The 50-month schedule, which was shorter than any theretofore achieved, was 11 months shorter than Bechtel's 61-month rebid proposal, which also used rolling 4-10 workshifts.

72. GSU did not perform any independent evaluation of the 50-month schedule.

73. Adoption of the 50-month schedule was based on the assumption that GSU could financially support the schedule, a proposition which was not tested beforehand and which proved to be untrue.

74. Adoption of the 50-month schedule was based on the assumption that vendor deadlines could be moved forward to meet the new schedule. That proposition was untested, and GSU and S&W indeed had serious problems with vendors' ability to meet the 50-month schedule's requirements.

75. The 50-month schedule when originally presented was premised on a scope of work identical to that set out in the May 1977 cost estimate——an obviously false assumption.

76. The 50-month schedule was untested and hastily conceived in order to assure that S&W would retain its role as constructor of River Bend.

77. GSU was imprudent in relying upon and pursuing the 50-month schedule.

78. GSU could reasonably have pursued a 60-month schedule, which would have still been quite rapid and would still have meant completion in record time.

79. The DCE should have included approximately $183 million for a 60-month rather than a 50-month schedule.

80. A reasonable manager in 1979 would have expected cost increases attributable to unresolved safety issues and TMI backfits to cost between $50 million and $100 million.

81. GSU should have added $50 to $100 million to the DCE for costs of unresolved safety issues and TMI backfits.

82. GSU generally effectively rebutted OKA's contention that many WPCNs and MCCs were improperly excluded from the DCE.

83. Changes reflected in WPCN 26, WPCN 200, WCPN 29, WPCN 118, and MCC 134, totalling approximately $18.370 million, were wrongly omitted from GSU's September 1979 estimate of plant costs based on the DCE.

84. WPCN 26, in the amount of $1.621 million, added fire protection headers. WPCN 200, in the amount of $2.504 million, pertained to the fireproofing of steel. Both were required by Appendix A which contained NRC fire protection requirements. Those costs should have been foreseen in September 1979.

85. In September 1979 GSU should have been aware of the existence of WPCN 29, which increased design costs of cooling towers by approximately $7.7 million.

86. In September 1979 GSU should have been aware of WPCN 118, which covered $221,000 worth of modifications to the radwaste building bridge crane.

87. In September 1979 GSU should have been aware of MCC 134 which added $6.324 million in additional costs for startup testing activities to be performed by S&W.

88. In September 1979, GSU should have expected River Bend to cost between $1.978 and $2.030 billion.

89. GSU was prudent in not including a formal contingency in its 1979 DCE.

90. GSU was indeed aware of the possibility of cost overruns and was certain of its ability to finance River Bend.

91. An appropriate informal contingency would have been 15 percent of to-go costs to cover not only known changes (such as those related to escalation or TMI), but

also known but unquantifiable changes (such as the costs of stricter ASMC piping criteria or ongoing vendor negotiations).

92. Sunken costs as of September 30, 1979 were approximately $412 million.

93. Applying a contingency of 15 percent of to-go costs to an expected cost of $2.030 yields a reasonable contingent estimate for financial planning purposes of approximately $2.273 billion.

94. The level of escalation set forth in the DCE was based upon detailed analyses of job components and contracts and on predictions by the President's Council of Economic Advisors.

95. MHB's application of the five-year Handy-Whitman construction cost escalation average of 9.3 percent was simplistic and skewed by an increase of 13.0 percent between 1974 and 1975, the first year of that five-year period. Removal of that year and reliance on a four-year average would yield an annual increase of 8.48 percent ——almost identical to the reasonable 10-year average identified by Mr. Curless of GSU, which was in line with the amounts actually included in the DCE.

96. The level of escalation set forth in the DCE was reasonable.

97. One of the three practitioners of the econometric estimating technique, Dr. Perl, in late 1978 disavowed its use as a basis for estimating future plant costs.

98. Use of an engineering estimate, with an appropriate contingency, was appropriate in late 1979 for estimation of River Bend's cost.

99. GSU was not imprudent in failing to consider the results of econometric estimation of nuclear plant costs in 1979.

100. Mark III containment issues appeared close to resolution in 1979.

101. To have included specific amounts for the resolution of Mark III issues in the DCE would have been speculative. Potential costs more appropriately would have been covered by a general financial planning contingency.

102. MHB predicted in 1978 that resolution of Mark III problems, including delays, would cost between $10 and $30 million.

103. It would not have been prudent to have deferred River Bend construction until Mark III issues were resolved.

104. All straightforward nuclear/coal busbar studies conducted at the level of the DCE suggested an economic cost advantage for nuclear power.

105. Dr. Pflaum's busbar comparison showed a cost advantage for nuclear generation at a $1.95 billion level. Dr. Pflaum found the breakeven point to be $2,300 per kW, or a capital cost of roughly $2.148 billion.

106. Dr. Andersen of OPC determined the nuclear/coal breakeven point to be at a capital cost of $2,135 per kW, or a capital cost of approximately $2.007 billion.

107. Busbar studies conducted at capital cost levels of $1.98 to $2.03 billion for River Bend would have been inconclusive or have shown a slight advantage for the nuclear option. Adding a 15 percent cost contingency to the nuclear estimate would probably have shown a slight advantage for coal.

108. The results of busbar analyses alone should not dictate generation planning decisions.

109. The financial uncertainties associated with nuclear power, although great, did not seem as overwhelming in 1979 as the ultimate costs of those plants would now imply.

110. Uncertainty as to coal prices, the potential for pollution from coal-fired generation, and the possible finan-

cial effects of River Bend cancellation argued in favor of nuclear power and the construction of River Bend.

111. The basic premise of Dr. Andersen's gas displacement analysis was that GSU could have built more coal-fired generation than nuclear generation for the same price. That additional generation would have displaced high-cost gas and helped GSU to meet its obligations under the Fuel Use Act.

112. Dr. Andersen used reasonable cost and technical assumptions in his gas displacement analysis.

113. The benefits of a gas displacement course depended upon the stringence of financial constraints and on predictions as to the volatile price of gas. The benefits of the gas displacement course therefore were themselves uncertain.

114. Dr. Andersen's selection of coal-fired generation as the optimal expansion path due to gas displacement did not take into account uncertainties attributable to coal prices, pollution, and River Bend cancellation.

115. Although Dr. Andersen's gas displacement analysis identified a reasonable alternative available to GSU, it did not show that the path pursued by GSU was imprudent.

116. GSU should not have planned its capacity expansion program on the unsubstantiated fear that its load projections would be drastically wrong.

117. GSU was not imprudent in proceeding with River Bend rather than building 300 MW coal units in order to protect its flexibility against volatile load growth.

118. GSU's decision to restart and build River Bend was prudent.

119. The CEPCO buyback enabled GSU to obtain participation in River Bend and provided power which GSU legitimately believed it would need during the first years of River Bend's operation.

120. The CEPCO buyback was a prudent transaction.

121. The Incremental Estimate File (IEF) was primarily a cost tracking and accounting tool and was designed to provide a detailed justification of cost increases.

122. The fact that GSU had a legitimate process for reviewing and approving changes in project costs does not show that those costs were reasonable.

123. The guidelines for coding changes to the regulatory category in the IEF limited the informative value of the IEF.

124. The PLG Report's analysis of the reasons for growth in the cost of River Bend was cursory and inadequate.

125. PLG has cited low cost per kW as an indicator of prudent management and as a key measure of management performance in other proceedings. The absence of a cost-per-kW comparison in this case damaged the credibility of the PLG report.

126. Although River Bend showed a relatively good ratio of man hours per commodity unit, it used more quantities for eight out of eleven and more man-hours for seven out of eleven commodities reviewed by PLG.

127. The OKA report, although more thorough than the PLG report, reached no conclusions as to imprudence during the construction of River Bend except as regards the 50-month schedule.

128. DELETED

129. Regulatory requirements unforeseen in 1979 had a significant if unquantified effect on the cost of River Bend.

130. The unique design features identified by Mr. Glazar of GSU did not significantly increase the cost of River Bend.

131. GSU could have developed a far more complete and accurate investigation of the reasons for the growth in River Bend costs.

132. GSU's non-statistical explanations of the reasons for the high capital cost of River Bend were inadequate and unconvincing.

133. At least $74,680,000 was imprudently spent in pursuit of the fuel load to first concrete 50-month construction schedule.

134. GSU has not proven how much of the $74,680,000 it spent in pursuit of the 50-month schedule would have been spent in any event.

135. S&W's engineering effort was inefficient to the point of wastefulness during the first year or so of the project.

136. The inefficiency of S&W's engineering effort was due at least in part to the rapid resumption of plant construction.

137. Pursuit of the 50-month schedule reduced construction productivity.

138. S&W's Engineering Management System (EMS) was in disarray through at least 1980.

139. Problems with EMS were aggravated by the 50-month schedule.

140. At least partly because it could not keep track of engineering status through EMS, GSU put its own engineers at S&W's Cherry Hills Operations Center (CHOC) in April 1980.

141. Problems with EMS deprived GSU of a valuable tool for project control.

142. Problems with EMS, the inefficiency of S&W engineering, and the reduction in productivity from pursuit of the accelerated schedule cannot be quantified accurately.

143. Neither GSU nor S&W was imprudent in the handling of TDI problems.

144. TDI itself was imprudent, as shown by the continual problems which culminated in the failure at Shoreham and the NRC's loss of confidence.

145. The direct costs of TDI problems to GSU totalled $8.1 million.

146. Although other expenses were probably incurred in resolving the TDI problems, MHB's calculation of an additional $54 million in "delay costs" was arbitrary and unsupported by any documentation.

147. GSU's handling of the Mark III problems, including the concrete annulus fill, was prudent.

148. The concrete annulus fill cost only $4 million.

149. Mark III problems caused no construction delays at River Bend.

150. MHB's calculation of $300-500 million in total post-1979 Mark III costs was completely unsupported and cast doubt on its entire analysis of the Mark III issue.

151. DELETED

152. The existence of identifiable imprudence and inefficiency in the construction and management of the plant as set forth in Finding of Fact Nos. 133-145 corroborates the exclusion of a portion of River Bend's capital costs from plant-in-service.

153.-161. DELETED

162. The fact that River Bend's costs are within a 90 or 95 percent statistical confidence interval does not explain or justify the high cost of the plant.

163. The statistical analyses presented in this docket were inadequate to prove the reasonableness or prudence of River Bend construction costs.

164. The preponderance of the evidence in this case establishes that $2.273 billion of River Bend capital costs were prudently and reasonably incurred. The evidence is inadequate to support a finding of either prudence or imprudence with regard to construction costs in excess of $2.273 billion, with the exception of the costs related to the 50-month schedule and TDI, addressed in Findings of Fact Nos. 133 and 145.

164A. GSU's share of all River Bend capital costs in excess of $2.273 billion should be excluded from plant in service at this time for lack of sufficient evidence as to the prudence and reasonableness of those costs. The amount which should be included in plant in service, given GSU's 70 percent share of the plant, is $1.5911 billion.

165. GSU's proposed rate moderation plan would defer the rate recognition of a portion of River Bend-related revenue requirements from the earliest years of operation to later years. GSU proposed to defer billing its Texas retail customers $202,900,000 of the first year's requirements, $107,800,000 of the second year's, and $49 million of the third year's. The cumulative balance of those deferred revenues would be included in rate base and earn a current return. In years 4-8, GSU proposed to recover the particular year's costs plus a specified percentage of the total cumulative deferred requirement.

166. A portion of the CEPCO buyback capacity payments should be disallowed to conform with the percentage of River Bend costs excluded from rate base. CEPCO buyback capacity payments should be calculated on a January-December 1988 rate year.

167. Because the CEPCO payments are a legitimate expense item prudently incurred, they should not be amortized over the life of the plant.

168. Deferred River Bend cash expenses through December 1987, along with return on those expenses, return on

investment, and depreciation through December 1987, should be included in GSU's rate base. Expenses after December 1987 should not be so included.

169. Deferred depreciation and return on investment should be reduced proportionately to conform with the amount of River Bend's cost disallowed from plant in service.

170. The accounting order deferrals and associated accumulated deferred Federal Income Tax (reflecting deferrals through December 31, 1987, the Commission's rate base treatment of River Bend, and one-half year's amortization) are $412,443,628 and $136,254,242, respectively.

171. In its interim rate order in this docket the Commission required GSU to offset its River Bend-related deferred expenses for Texas retail ratemaking purposes by an amount of $1.50 for each dollar of interim increase collected from Texas retail ratepayers.

172. The 1.5 times interim revenue offset of deferred expenses should be imposed in GSU's next rate case.

173. GSU did not incur any current tax liability by virtue of the interim rate increase authorized by the Commission in this docket.

174. Deferred River Bend expenses should be offset by 1.5 times the interim revenues collected by GSU, not by .90 times that amount as proposed by GSU.

175. It is reasonable to allow return on deferred cash expenses in rate base.

176. Because excess deferred taxes would serve to reduce the company's rate base, deferred River Bend expenses should not be reduced by the amount of excess deferred taxes held by GSU.

177. Amortization of deferred expenses over 40 years would recognize that deferred accounting is extraordinary regulatory treatment and that the deferred accounting

order in Docket No. 6525 has fulfilled the purpose of protecting GSU's financial condition during a period of regulatory lag.

178. Deferred River Bend expenses should be amortized over a 40-year period.

179.-190. DELETED

191. A phase-in rate moderation plan is not necessary at this time to protect ratepayers' interests, considering the revenue levels which will be produced by the Commission's Order, although such a plan may be appropriate in the future if additional River Bend capital costs are found to have been reasonably and prudently incurred.

192. DELETED

193. GSU's proposed true-up mechanism for River Bend-related revenues should be rejected.

194. River Bend contra-AFUDC should be amortized over ten years.

195. River Bend is expected to operate for 40 years or more.

196. A 40-year service life is reasonable for calculating annual depreciation expense for River Bend.

197. River Bend should be depreciated at a 2.5 percent annual rate.

198. Annual River Bend-related depreciation expense, after exclusion of costs not found to be prudent, is $39,548,636.

199. The external fund method provides assurance that River Bend decommissioning funds will be available when needed, and should be approved.

200. GSU's cost estimate for River Bend decommissioning expense, including a 25 percent contingency, is reasonable.

201. An inflation-adjusted decommissioning payment stream would ensure that present and future customers pay equal shares of River Bend decommissioning expense.

202. Annual decommissioning expense of $2,243,019 should be included in GSU's system-wide cost of service in this docket.

202A. Annual decommissioning expense should not be included in GSU's deferral amounts and should instead be calculated and included in cost-of-service based on River Bend's remaining service life as of December 31, 1987.

202B. Amounts identified and approved by the Commission for decommissioning expense should be placed in a qualified tax-free irrevocable trust fund to ensure their availability and use for the decommissioning of River Bend.

203. TIEC's proposed performance standard is simplistic and its ramifications have not been fully investigated in the course of this rate proceeding.

204. The evidence does not show that imposition of an interim performance standard for River Bend would be necessary or desirable.

205. The preponderance of the evidence establishes that GSU has a total invested capital with components as set forth in Schedule IV of the Order.

206. GSU's net investment in Nelson Units 1 and 2 should not be included in rate base, because the preponderance of the evidence establishes that the units are not used and useful to the company in providing service and because the plants have been sold by GSU.

207. The preponderance of the evidence supports approval of the uncontested items in net electric plant in service requested by GSU.

208. It is appropriate to adjust accumulated depreciation as requested by GSU to reflect the transfer of Nelson Unit 7 to the steam department.

209. The staff's adjustments reversing GSU's accumulated depreciation adjustment, which adjusts accumulated depreciation by one-half the incremental amount of depreciation expense, should be adopted for the reasons given by the staff and set forth in section VII.B of this Report, except those adjustments related to River Bend and set forth in Finding of Fact No. 212.

210. The averaging adjustment to accumulated depreciation, recommended by the Cities, should be rejected because it conflicts with the goal of synchronizing—except for known and measurable changes—company revenues, expenses, and investments at test-year-end levels.

211. In accordance with the parties' stipulation in Docket No. 6525, adopted by the Commission, GSU should be allowed to defer $3,065,619 of accumulated depreciation related to Big Cajun 2 Unit 3.

212. GSU's and the Cities' adjustments to accumulated depreciation to River Bend, and related adjustments to deferred federal income tax, should be adopted to reflect recovery of deferred depreciation expense from June 16, 1986, through December 31, 1987.

213. The $49,491,492 of deferred payments to Stone and Webster are contractual obligations that are in effect a promissory note in lieu of immediate payment; the payments thus represent a capital expense that should be included in rate base, and a like amount should be included in the total capitalization of GSU as an interest-free loan.

214. The Cities' recommendations pertaining to the capitalized River Bend advertising expenses are reasonable; accordingly, the $3,091,662 of capitalized advertising expenses should not be included in plant in service.

214A. The Cities' recommendations pertaining to accrual of AFDUC on River Bend should be rejected for the reasons stated in Section VII.C.4 of the Examiners' Report.

215. GSU does not have definite plans to place the Blue Hills site in service within 10 years; accordingly, the company's $4,215,997 investment in the land and the associated transmission lines and rights-of-way should not be included in PHFU.

216. GSU does not have definite plans to place the equipment at Nelson Unit 5 in service within 10 years; accordingly, the company's $23,343,000 investment in the equipment should not be included in PHFU.

217. GSU does not have definite plans to place the following units in service within 10 years: Neches Units 4, 5, and 6 and Louisiana Units 7, 8, and 9; accordingly, the company's investment in these units should not be included in PHFU.

218. On the basis of the stipulation (Joint Exhibit No. 1) and the testimony of GSU witness Loggins, GSU's $7,436,478 net investment in Neches Unit 8 is properly includible in PHFU.

219. GSU's requested amount for materials and supplies should be reduced by $640,264 to allow for the downward trend in the company's inventory levels during and since the end of the test year.

220. The staff's recommended fuel inventory for GSU of $9.1 million should be approved for the reasons stated in section VII.E.2 of this Report.

221. The Cities' recommendation to exclude prepayments for liability insurance from rate base should be rejected because the liability insurance is properly part of GSU's cost of service.

222. The Cities' recommendation to exclude $65,092 of coal cost and include $13,576 of prepaid rating service

fees to reflect known and measurable changes should be approved.

223. The staff's adjustments to cash working capital should be adopted for the reasons stated in section VII.E.4 of this Report.

224. The Cities' recommendations with respect to minimum cash balances, coal and materials-and-supplies lead days, federal income tax lead days, and mail float should be rejected for the reasons stated in section VII.E.4 of this Report.

225. GSU's end-of-test-year adjustment of deferred federal income taxes to reflect a 37 percent income tax rate should be reversed as recommended by the staff except that the excess deferred federal income taxes should be flowed back to the ratepayers over a three-year period.

226. GSU need not maintain vintaged deferred tax accounts, because such accounts are not required by the Uniform System of Accounts and the cost of maintaining such accounts would not be justified.

227. GSU's deferred income taxes should be adjusted to reflect a decrease of $3,065,619 in accumulated depreciation related to Big Cajun 2 Unit 3.

228. With the exception of the adjustment related to Big Cajun 2 Unit 3, the staff's recommended adjustments to accumulated deferred income taxes should be approved for the reasons stated in the summary of Mr. McKinney's testimony in section VII.F. of this Report.

229. GSU should not be allowed to earn a return on the unamortized management audit expense because that expense is non-recurring and should have been written off by the time the rates approved in this docket take effect.

230. According to the preponderance of the evidence, ratepayers have contributed 70 percent of the funds in

the safety achievement reserve and the company has contributed 30 percent of the funds; accordingly, the reserve should be reduced by 30 percent of its end-of-test-year level, or $98,705, to enable the shareholders to earn a return on the funds they contributed.

231. GSU's adjustment to the end-of-test-year balance of nuclear fuel Contra-AFUDC should be reversed to consistently eliminate the accumulated depreciation adjustments as recommended by the staff.

232. The appropriate method of determining the rate of return for GSU is to determine the weighted average cost of capital.

233. DELETED

234. The preponderance of the evidence establishes that a reasonable return on equity for GSU is 13.0 percent.

235. For the reasons stated in section VII.B. of this Report, the appropriate capital structure of GSU to be used to determine its return on capital is that for January 1987.

236. The appropriate capital structure cost of capital by classes, and weighted average cost of capital to GSU are as set forth in Schedule VIII of the Order.

237. Allowing GSU a return on equity of 13.0 percent and a weighted average cost of capital of 11.48 percent will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

238. The preponderance of the evidence establishes that GSU has a total revenue requirement with components as set forth in Schedule I of the Order.

239. The preponderance of the evidence establishes that GSU's fuel and purchased power expenses are as follows:

	(000s)
Purchased Power	
Reconcilable	$113,605
Nonreconcilable	116,479
Fuel	
Reconcilable	365,739
Nonreconcilable	4,096
Total	$662,059

240. Because of its difficult cash situation, GSU should be authorized to refund its cumulative fuel overrecovery through its fixed fuel factor over a 12-month period.

241. The preponderance of the evidence establishes an operations and maintenance expense with components as set forth in Schedule II of the Order.

242. The preponderance of the evidence supports approval of the uncontested items of operations and maintenance expense requested by GSU.

243. The unrebutted adjustments recommended by the staff and summarized in section IX.C.2. of this Report should be approved for the reasons stated in that section.

244. For the reasons stated in section IX.C.3.c of this Report, GSU's payroll expense ratio is 80 percent.

245. The proper adjustments for dental insurance and health insurance expenses are those calculated by the staff, which are based on actual, rather than projected, data. The staff's adjustments to the company's requested amounts are presented in section IX.C.4.b of this Report.

246. The adjustment to pension plan expense should reflect the actual 1986 contribution. For the reasons stated in the testimony of Mr. Willis and summarized in section IX.C.4. of this Report, the proper way to calculate the funding requirements of the pension plan is on a present value basis with the funding to occur over the estimated life of the expense. Accordingly, the annual funding re-

quirements are $867,695 (total electric basis), and a corresponding adjustment should be made to rate base.

247. The adjustment to storm damage reserve expense should be based on four years of data, as calculated by GSU, but adjusted to exclude the amounts charged to CWIP.

248. DELETED

249. For the reasons stated in section IX.C.7.e. of this Report, the adjusted premiums for GSU's liability insurance are a reasonable and necessary expense of providing utility service.

250. The preponderance of the evidence establishes that GSU's reasonable and necessary rate case expenses total to the amount set forth in Schedule II and Attachment 2 of the Order. Because of the large amount of recoverable expenses, a surcharge for two years is the most appropriate method of allowing GSU to recover its rate case expenses.

250A. GSU failed to establish by a preponderance of the evidence that the $683,421 of Account No. 928 charges set forth in Attachment 2 are reasonable and necessary expenses. Accordingly, these expenses are not properly includible in the company's rate case expenses.

250B. GSU failed to establish by a preponderance of the evidence that the four invoices totaling $51,708 in Attachment 2 represent reasonable and necessary expenses for services in this rate case. Accordingly, these expenses are not properly includible in the company's rate case expenses.

250C. The $1,461,329 of GSU employee payroll actual expenses and $132,000 of estimated expenses are properly includible in the company's operating expenses and not properly includible in rate case expenses.

250D. GSU established by a preponderance of the evidence that the $8,395 of leased airplane and $33,016 of

temporary employment expenses are reasonable and necessary and properly includible in rate case expenses.

250E. GSU established by a preponderance of the evidence that the following expenses are reasonable and necessary: court reporting services, $240,915; employee personal expenses, $174,783; and miscellaneous expenses, $300,218. GSU failed to establish the following estimated expenses are reasonable: court reporting service, $40,000; employee personal expenses, $27,000; and miscellaneous expenses, $30,000.

250F. GSU failed to provide sufficient information to establish by a preponderance of the evidence that all expenses it incurred for outside attorneys and consultants are reasonable and necessary. A reasonable alternative method of establishing the reasonable and necessary expenses is to allocate to Texas a portion of the total of such expenses incurred in both Texas and Louisiana. The power pool factor of 40.7725 percent established by GSU in Docket No. 7195 is the reasonable portion to allocate to Texas. Accordingly, $3,751,688 of GSU's expenses for outside attorneys and consultants is properly includible in rate case expenses.

250G. Through the testimony of Alan Holman and Jack Pous as summarized in Attachment 2, the Cities established by a preponderance of the evidence that they should be reimbursed by GSU for reasonable and necessary rate case expenses that include the following actual and estimated items: Butler & Casstevens, $353,637; Naman, Howell, Smith & Lee, $1,300; Diversified Utility Consultants, $289,657; Pannell Kerr Forster, $83,923; and court reporting expenses, $9,629.

250H. Through the testimony of the local counsel as summarized in Attachment 2, the Cities established by a preponderance of the evidence that the following cities should be reimbursed by GSU for reasonable and necessary rate case expenses as follows: Bridge City, $8,679; Groves, $16,172; Nederland, $29,472; Port Arthur, $2,606;

Port Neches, $23,071; Rose City, $7,289; and Vidor and Bevil Oaks, $14,610.

250I. Through the testimony of Jim Boyle as summarized in Attachment 2, CAUR established by a preponderance of the evidence that it should be reimbursed by GSU for reasonable and necessary rate case expenses that include actual expenses of $169,506 and estimated expenses of $40,000, or a total of $219,506. CAUR failed to establish that the $3,406 it requested for Judge Whelan's services was a reasonable and necessary expense.

250J. The preponderance of evidence establishes that the reasonable and necessary rate case expenses, as set forth in Findings of Fact Nos. 250G-H, of CAUR and the Cities include the expenses necessary for their counsel to file amicus briefs in the *HL&P* case (Case No. C-5705) on motion for rehearing before the Texas Supreme Court.

250K. Through the testimony of Geoffrey Gay as summarized in Attachment 2, the Public Parties Committee (PPC) established by a preponderance of the evidence that it should be reimbursed by GSU for reasonable and necessary expenses of $331,783. Although GSU paid PPC $455,980 pursuant to their agreement, $124,197 of the amount paid is properly allocable to the Louisiana rate case in accordance with the allocation method used in Finding of Fact No. 250F, because identical testimony was filed by OKA and KEA in Texas and Louisiana.

250L. The preponderance of the evidence established that GSU's reasonable and necessary rate case expenses include $24,154 paid to Decision Management Services and $20,966 paid to QED Research, the consultants to the Commission staff.

251. Although GSU retained a balance of $94,938 in the safety achievement reserve when it terminated the associated safety program, the ratepayers do not have an interest in or claim against that amount of funds. Setting GSU's future rates at a level to transfer the re-

serve to the ratepayers would require that rates be below the level needed for the company to earn a reasonable return above costs. Accordingly, the adjustments recommended by the staff and the Cities to reduce cost of service by the amount of the reserve are improper and should be rejected.

252. For the reasons stated in section IX.C.10 of this Report, GSU's requested trade association dues expense, as modified by Mr. Bellon, is a reasonable and necessary expense.

253. For the reasons stated in section IX.C.11.d., the Cities' recommendation to exclude the long-term storage cost of generating units from cost of service should be rejected, and the $2,342,250 should be included in costs as a necessary and reasonable expense.

254. For the reasons stated in the summary of the staff and company testimony in section IX.C.12 of this Report, the Edison Plaza lease payment—as adjusted by the staff—is a reasonable and necessary expense, of which 94.82 percent should be charged to operations and maintenance expense and the remainder capitalized.

255. It is appropriate to adjust operations and maintenance expense as recommended by the staff to avoid overrecovery by GSU as a result of CEPCO's reimbursements to GSU for direct costs and overhead charges.

256. The preponderance of the evidence establishes that the $6,929,202 of gains on disposition of assets discussed in section IX.C.14 of this Report were properly recorded by GSU below the line as nonrecurring events that are not part of cost of service.

257. Because the economy in GSU's service area has recently worsened, the test year expense factor better represents the company's current experience with uncollectible expense than does a factor based on a four-year average. Accordingly, the adjustments recommended by the staff and the Cities should be rejected, and uncol-

lectible expense should be based on the test year expense factor.

258. For the reasons stated in section IX.C.16.d. of this Report, the $860,681 requested by GSU as coal car maintenance reserve accruals is a reasonable and necessary expense, and the Cities' adjustment to the accruals should be rejected.

259. The testimony of the company witnesses summarized in section IX.C.17 of this Report establishes, by a preponderance of the evidence, that GSU does not have sufficient receivables to raise the amount of cash that the Cities witnesses assumed possible and that in the long run, it is less expensive for GSU to borrow funds by using its accounts receivables as collateral than by factoring the receivables. Accordingly, the recommendation of the Cities witnesses to adjust cost of service to reflect the hypothetical cost of raising cash by factoring receivables should be rejected.

260. The preponderance of the evidence, as summarized in section IX.C.18 of this Report, establishes that GSU has not underestimated the savings from its recently implemented meter reading system. Accordingly, the Cities' recommendation to reduce cost of service by $605,188 to take into account extra savings should be rejected.

261. GSU failed to demonstrate by a preponderance of the evidence that the depreciation expense associated with Nelson Units 1 and 2 should be included in cost of service as a reasonable and necessary expense.

262. In accordance with the parties' stipulation in Docket No. 6525, depreciation expense of $84,763 related to Big Cajun 2 Unit 3 should be included in cost of service.

263. For the reasons stated in section IX.D.4 of this Report, interim retirements and additions related to

GSU's generating units can be most simply and accurately accounted for by using end-of-test-year account balances when the company files for rate increases.

264. For the reasons stated in section IX.D.4 of this Report, the most reasonable estimated net salvage value of GSU's production plant is negative 5 percent.

265. The Cities' recommendation to base the remaining life of common plant facilities at each station on the remaining life of the last-retired generating unit would properly amortize the cost of the facilities over their service life. Accordingly, the Cities' recommendation should be adopted.

266. For the reasons stated in section IX.D.4.e. of this Report, the half-year convention is an appropriate way of determining average service lives and calculating depreciation rates for generating units.

267. As recommended by the Cities, the remaining life of the land rights associated with transmission lines should be based on the endpoint of the transmission equipment survivor curve.

268. The preponderance of the evidence establishes as reasonable the remaining salvage values and depreciation rates proposed by GSU for transmission, distribution, and general plant, with the minor modification recommended by Mr. Rogas.

269. The reasonable and necessary interest on the $14,851,568 of customer deposits held by GSU is $891,094 calculated at the statutory interest rate of 6.0 percent as recommended by the staff.

270. The preponderance of the evidence establishes that GSU incurs taxes other than income taxes with components as set forth in Schedule III of the Order.

271. For the reasons stated in section IX.F.1 of this Report, GSU's pro forma increase of $1,013,867 to its test

year payroll taxes is reasonable; however, the increase must be modified so that payroll taxes related to Nelson Units 1 and 2 are treated in a manner consistent with the treatment of the other items related to those units.

272. For the reasons stated in section IX.F.2 of this Report, GSU's pro forma increase in ad valorem taxes of $2,353,750 is reasonable.

273. On the basis of the staff testimony summarized in section IX.F.3 of this Report, GSU Texas franchise taxes of $5,854,028 are reasonable.

274. The staff's method of calculating the comptroller's audit fee is reasonable and should be adopted; however, the fee should be amortized over a four-year period as recommended by the Cities.

275. The preponderance of the evidence supports the staff-recommended $5,996,211 decrease to GSU's requested amount for revenue-related taxes other than income taxes.

276. The preponderance of the evidence supports the staff's tax calculation procedure to calculate a level of state income taxes.

277. For the reasons stated in section IX.H.6 of this Report, 34 percent is the proper tax rate to calculate GSU's federal income tax expense.

278. The preponderance of the evidence establishes a federal income tax expense as set forth in Schedule I of the Order, calculated as the Alternative Minimum Tax that GSU would incur on a stand-alone basis, plus an amount for the normalization of accelerated depreciation.

279. The preponderance of the evidence does not support the Cities-recommended adjustment to reflect consolidated tax savings.

280. For the reasons stated in section X of this Report, the staff-recommended adjusted electric sales are reasonable and should be adopted.

281. For the reasons discussed in Section XI.B.1., the interdepartmental eliminations and reclassifications proposed by GSU should be approved for purposes of the jurisdictional separations process.

282. For the reasons discussed in Section XI.B.2.a., production and transmission tie line capacity costs and related expenses should be allocated between jurisdictions using the A&E-MDD methodology.

283. As discussed in Section XI.B.2.b., uncollectible expense should be allocated between jurisdictions using a test year ratio rather than the four year average ratio proposed by the Commission staff.

284. Non-tie line transmission facilities should be allocated on a "rolled-in" basis for purposes of the jurisdictional separation study in order to preserve a consistent approach between jurisdictions.

285. For purposes of calculating jurisdictional separation factors for production and transmission tie facilities, both weather adjusted kWh and kW should be used. If weather adjusted kW cannot be calculated using the methodology employed to calculate Schedule 0-1-G, then neither kWh or kW should be adjusted for weather.

286. GSU's allocation factor for accumulated provision for depreciation should be used in the jurisdictional cost of service study, for the reasons cited in Section XI.B.2.f. of the Report.

287. For purposes of the jurisdictional cost of service study, the staff's adjustments to PHFU should be allocated using separate transmission tie line and transmission non-tie line allocators rather than using a composite allocator, in order to produce a more equitable allocation between jurisdictions.

288. Consistent with the Commission's adoption of staff witness Bellon's proposed adjustment of O&M expense for CEPCO reimbursements, CEPCO reimbursements should be considered an expense of the Texas retail jurisdiction.

289. For the reason stated in Section XI.B.2.i., GSU's original specifically assigned allocation factors for allocation of revenue requirement deferrals and associated deferred taxes should be corrected in order to accurately allocate revenue requirement deferrals and associated deferred taxes, based upon the prudence and rate moderation recommendations adopted by the Commission.

290. For the reasons discussed in Section XI.C.1., and subsections thereof, A&E-MEE should be used to allocate GSU's production and transmission capacity costs between GSU's Texas retail customer classes.

291. For the reasons discussed in Section XI.C.2., non-tie transmission facilities should be allocated between customer classes on a "non-rolled-in" basis.

292. Interruptible demand should be removed from class loads in allocating the expense associated with interruptible credits, for the reasons stated in Section XI.C.3.

293. Uncollectible accounts expense should be allocated to all customer classes using a ratio of class operating revenues to total operating revenues, as proposed by staff witness Miphan.

294. Texas wholesale demand and energy data should be excluded from the calculation of excess demand at the Texas retail level.

295. Rate comparability between Texas and Louisiana should not be viewed as an appropriate consideration in allocating revenue requirement among Texas retail customer classes, for the reasons cited in Section XI.D.6.

296. Any revenue spread adopted by the Commission should be designed to produce movement of the residential class toward relative unity.

297. Maintenance of appropriate class crossing points should be achieved to the extent possible through rate design rather than through allocation of revenue requirement.

298. For the reasons described in Section XI.D., and subsections thereof, the revenue distribution guidelines listed in Section XI.D.6 are appropriate for use in this docket and should be approved.

299. A separate rate class should not be established for State Agencies, nor should they receive special rate treatment.

300. The residential customer charge should remain at its current level of $7.00 per month, for the reasons stated in Section XII.A.1.

301. GSU's proposal to expand the current residential winter tail block differential from 2¢ to 2.5¢ should be rejected, for the reasons stated in Section XII.A.2.

302. The Good Cents Rider should be permitted to remain in effect, and the lost revenues attributable to the Rider should be borne exclusively by the shareholders.

303. The SGS customer charge should be reduced from $17.70 to $14.00 for the reasons stated in Section XII.B.

304. A summer/winter demand charge differential should be incorporated into the restructured LPS and HLFS rate classes, for the reasons stated in Section XII.C.1.a.

305. The LPS and HLFS voltage level adjustment charges proposed by GSU should be approved for the reasons stated in Section XII.C.1.b.

306. The interruptible credits of $6.00 and $3.60 proposed by GSU should be applied to the 5 minute and 30 minute notice categories, respectively.

307. The penalty for non-compliance with a request to interrupt load should be increased to four times the firm load kW charge for all kW in excess of firm contract power, as proposed by GSU.

308. The language contained in the proposed IS rider pertaining to permissible reasons for load interruption

should be revised in the manner indicated in Section XII.C.2.c., for the reasons stated in that section.

309. For the reasons stated in Section XII.C.2.d., GSU's proposal to include a 20 percent ratchet in the consolidated IS rider should be approved with the understanding that existing interruptible customers must be permitted a one-time option to revise the level of their contract interruptible load.

310. Future GSU annual system peak load forecasts should be adjusted to exclude coincident interruptible loads subject to 30 minute interruption notice, for the reasons stated in Section XII.C.2.e.

311. The "experimental" designation should not be removed from Schedule IS, nor should any limitations be placed on the number of interruptions which may occur in any given day, for the reasons stated in Section XII.C.2.f.

312. The current facilities charge rate for Schedules LPS and LIS should not be changed, for the reasons stated in Section XII.C.3.

313. Schedule RRI-S should not be adopted, for the reasons set forth in Section XII.D.

314. Except as otherwise indicated in this Order, the company's proposed rate design is reasonable and should be approved.

315. The fixed fuel factors set forth in Schedule VII of the Order are reasonable and should be approved.

316. The staff's proposed revisions to GSU's service rates and regulations should be approved with the exception of the proposed revision to Section IV, Sheet No. 1, Sec. 20, which should be rejected for the reasons stated in Section XIII.B. of the Report.

317. Except as otherwise indicated the company's proposed tariff should be approved.

B. *Conclusions of Law*

1. The Commission has jurisdiction and authority in this case, including consideration of the consolidated appeals from the cities listed in Finding of Fact No. 6 and the prudence of GSU with respect to River Bend, pursuant to Sections 16, 17(d) and (e), 26, 37, 41 and 43 of PURA.

2. GSU is a public utility as defined by Section 3(c)(1) of PURA.

3. The rate filing package filed by GSU meets the requirements for a statement of intent set forth in Section 43(a) of PURA.

4. The operation of the proposed rate schedule was suspended in accordance with Section 43(d) of PURA.

5. Proper notice was given to all affected persons in compliance with Section 43(a) of PURA.

6. GSU has substantially complied with the requirements for energy efficiency plans set forth in P.U.C. SUBST. R. 23.22.

7. The proceedings in Docket Nos. 857 and 1527 did not meet the standard articulated by the Supreme Court in *U.S. v. Utah Mining and Construction Company*, 384 U.S. 344, 421-22; 86 S.Ct. 1545, 1560 (1966) for application of the doctrine of res judicata to prohibit inquiry into the prudence of the decision to build the River Bend plant.

8. The Commission's decisions in Docket Nos. 857 and 1527 do not preclude the Commission from considering in this docket the prudence of the decision to build the River Bend plant.

9. The argument that once a CCN is granted the Commission may not question a utility's decision to continue to construct a power plant, even if projected load vanishes, capital costs skyrocket, and alternative methods of serv-

ing the public clearly become economically preferable, is inconsistent with the Commission's responsibilities under PURA Sections 2, 38, 41, and 43.

10. Pursuant to PURA Sections 16(a), 38, 39(a), and 41, the Commission may reexamine on rehearing or in a subsequent proceeding the prudence and reasonableness of those River Bend construction costs regarding which the evidence is inadequate to support a finding of either prudence or imprudence.

11. The prudent investment test is embodied in traditional ratemaking principles as expressed through PURA Sections 2, 38, 39, and 41.

12. The Commission has the responsibility and authority to exclude imprudent or wasteful expenditures from invested capital pursuant to PURA Sections 38, 39, and 41.

13. The Commission has the responsibility and authority to disallow imprudently or wastefully incurred expenses pursuant to PURA Sections 38, 39, and 41.

14. The standard of prudence to be applied in establishing the amount of invested capital used and useful in rendering service to the public is as follows:

> the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.

15. Under PURA Section 40 a utility must prove its conduct to have been prudent when decisions or expenditures are reasonably challenged.

16. The decision to build River Bend was prudent as that term is defined in Conclusion of Law No. 14.

17. The CEPCO buyback agreement was a prudent transaction as that term is defined in Conclusion of Law No. 14.

18. $1,453,520,982 of GSU's share of end-of-test-year River Bend capital costs should not be included from GSU's rate base as invested capital used and useful in rendering service to the public pursuant to PURA Sections 38, 39, and 41.

18A. GSU has not met its burden of proving that the capital costs of River Bend above a reasonable Definitive Cost Estimate of $2.273 billion were reasonably and prudently incurred.

19. Expenses associated with the capital costs of River Bend not included in plant in service, including the capacity portion of the CEPCO buyback expense, River Bend depreciation expense, and deferred River Bend depreciation expense and return on investment should not be included from cost of service pursuant to PURA Sections 38, 39, and 41.

20. A mere showing that statistical adjustments to plant costs are unreliable or that plant costs are within the range suggested by statistical confidence intervals is inadequate to meet a utility's burden of proof under PURA Section 40.

21.-23. DELETED

24. As required by Section 41(a) of PURA, the net plant component of GSU's invested capital set forth in Schedule IV of the Order is based upon the original cost of property used by and useful to GSU in providing utility service.

25. The methods and rates of depreciation implicit in Schedules I and IV of the Order are proper and adequate and have been uniformly and consistently applied, as required by Section 27(b) of PURA.

26. To the extent included in invested capital, GSU's generation, transmission, and distribution facilities are safe, adequate, efficient, and reasonable, as required by Section 35(a) of PURA.

27. The overall rate of return and component rates of return allowed by Schedule VI of the Order substantially comply with P.U.C. SUBST. R. 23.21(c)(1).

28. Taking into consideration GSU's quality of management, quality of service, effort to conserve energy and resources, and efficiency of operations, the return set forth in Schedule I of the Order constitutes a reasonable return on GSU's invested capital used and useful in rendering service to the public, as required by Section 39(b) of PURA.

29. The return set forth in Schedule I of the Order will permit GSU a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses, as required by Section 39(a) of PURA.

30. Under the circumstances of this case, transferral back to ratepayers of unredeemed, previously accrued safety achievement reserves by reducing future rates would constitute prohibited retroactive ratemaking.

31. A gain from an asset transfer should be distributed between ratepayers and shareholders in accordance with which group had borne the risk of capital loss on the asset.

32. GSU has met the burden of proof imposed by Section 40 of PURA to show that rates producing the total revenue set forth in Schedule I of the Order are just and reasonable.

33. The rates and rate design implied by the customer-class revenue requirements in Schedule V of the Order are just and reasonable and are not unreasonably preferential, prejudicial, or discriminatory within the meaning of Section 38 of PURA.

34. As required by Section 45 of PURA, the implied rates and rate design do not grant an unreasonable preference or advantage to any customer within a classifica-

tion, subject any customer within a classification to an unreasonable prejudice or disadvantage, or establish unreasonable differences as to rates or service between localities or between classes of service.

35. The rates approved by the Commission in this case are to be effective only for customers in areas within the Commission's original jurisdiction and in the cities from which appeals were consolidated with this case.

36. There exists no Constitutional or statutory requirement that rates paid for utility service by state agencies must be fixed at a level equal to cost, assuming a relative rate of return at unity, as determined by a class cost of service study.

37. The rates implied by Schedules I-VIII of the Order are just and reasonable and otherwise comply with the ratemaking mandates of Article VI of PURA and should be approved.

DOCKET NOS. 6755 AND 7195
RATE CASE EXPENSES

Description	Amount Requested	Amount Disallowed	Amount Allowed
1. Test Year Non-Rate Case 928 Charges			
-PUCT Mgt. Audit-1985 (E1928002)	$ 231,159.86	$ 231,159.86	$ -0-
-River Bend Task Force (E1928015)	271,279.69	271,279.69	-0-
-Southern Co. Litigation (E1928032)	50,249.66	50,249.66	-0-
-Allocable (E1928001) 92.639.01 x 91.88%	85,116.72	85,116.72	-0-
-Docket 5798-Sabine River Authority (E1928035) 47,457.31 x 91.88%	43,603.78	43,603.78	-0-
-Allocable (E1928039) 2000.00 x 91.88%	1,837.60	1,837.60	-0-
-Allocable (C199911) 189.20 x 91.88%	173.84	173.84	-0-
SUBTOTAL	683,421.15	683,421.15	-0-

Description	Amount Requested	Amount Disallowed	Amount Allowed
2. Adjustments for Reclassification of Certain Charges			
-Marshall Bartlett, Inc. (Voucher No. 020484)	$ 36,646.89	$ 36,646.89	$ -0-
-S.M. Stoller (Voucher No. 03966)	14,711.68	14,711.68	-0-
-Coopers & Lybrand (Voucher No. 042158)	135.00	135.00	-0-
-Coopers & Lybrand (Voucher No. 042160)	214.00	214.00	-0-
SUBTOTAL	51,707.57	51,707.57	-0-
3. Adjustment to Re-Classify Tx. Portion of River Bend Prudency	438,380.24	438,380.24	-0-
SUBTOTAL	438,380.24	438,380.24	-0-
-GSU Employees Payroll	1,461,329.45	1,461,329.45	-0-[1]
(Jan-Mar Estimate)	132,000.00	132,000.00	-0-
-GSU Leased Airplane	8,394.73	-0-	8,394.73
-Temp. Employment	33,016.36	-0-	33,016.36
-Court Reporting	240,914.63	-0-	240,914.63
Services	40,000.00	40,000.00	

[1] This amount was included in operating expenses.

-GSU Employees Personal Expenses	174,783.24		174,783.24
-Miscellaneous Expenses	27,000.00	27,000.00	
	300,218.20		300,218.20
	30,000.00	30,000.00	
SUBTOTAL	2,447,656.61	1,690,329.45	757,327.16
-GSU Outside Consultants			
-Bishop, Lieberman & Cook	$ 43,509.45		
-Cajun Elec. Power	4,406.04		
-Coopers & Lybrand	164,968.75		
-Int'l Energy Assoc.	80,839.12		
-John Borcherding	48,468.86		
-LJS Consulting Svc.	27,007.61		
-Mgmt. Analysis Co.	403,768.98		
-Marshall Bartlett, Inc.	276,131.47		
-Nat'l Economic Research Assoc.	244,764.80		
-Olson & Co.	70,922.24		
-Pickard, Lowe & & Garrick	88,462.44		
-Putnam, Hayes & Bartlett	673,693.66		
-Reg Res. Assoc.	22,869.15		
-Reid & Priest	37,391.60		
-Richard Pettway & Associates	30,654.00		
-S.M. Stoller Corp.	12,614.93		
-Scott Consulting Group	54,323.59		
-Stone & Webster	50,861.50		
	16,584.69		

See Next Page

Description	Amount Requested	Amount Disallowed	Amount Allowed
-Tim D. Martin & Associates	204,365.23		
-TLG Enginerring	6,157.98		
-Wyatt Co.	6,600.00		
SUBTOTAL	2,569,366.09		
-GSU Outside Attorneys			
-Cadwalader, Wickersham & Taft			
-Professional Services	2,953,045.63	See Next Page	
-Estimate of 12/87 Invoice	200,000.00		
-Holdback Provision thru 12/87	650,000.00		
-Transportation	159,562.13		
-Other Expenses	218,700.61		
-Estimate	473,382.00		
SUBTOTAL	4,654,690.37		

-Clark, Thomas, Winters & Newton			
-Professional Services	$ 18,907.50	$	$
-Food	2.00		
-Transportation	370.86		
-Other Expenses	1,454.17		
SUBTOTAL	20,734.53		
-Cohan, Simpson, Collishaw, Oranza & Wulf			
-Professional Services	337,825.00		
-Estimate (12/87 Invoice)	60,000.00		
-Food	555.58		
-Transportation	9,234.45		
-Other Expenses	17,594.16		
-Estimate	30,798.86		
SUBTOTAL	456,008.05		
-James Tourtellotte			
-Professional Services	37,738.65		
-Other Expenses	394.76		
SUBTOTAL	38,133.41		
SUBTOTAL FOR GSU OUTSIDE ATTORNEYS AND CONSULTANTS	7,738,932.45	3,987,244.62	3,751,687.83 [2]

[2] For calculation of amount, see Page 8 of 10 [App. 96a].

Description	Amount Requested	Amount Disallowed	Amount Allowed
-Cities Attorneys and Consultants			
-Butler & Casstevens			
-Professional Fees and Other Expenses	$ 353,637.10	$ -0-	$ 353,637.10
-Court Reporting Serv.	9,628.75	-0-	9,628.75
SUBTOTAL	363,267.85	-0-	363,267.85
-Diversified Utility Consultants			
-Professional Serv.	289,656.90	-0-	289,656.90
SUBTOTAL	289,656.90	-0-	289,656.90
-Parnell, Kerr & Foster			
-Professional Services	79,977.00	-0-	79,977.00
-Expenses	3,946.43	-0-	3,946.43
SUBTOTAL	83,923.43	-0-	83,923.43
-Naman, Howell, Smith & Lee	1,300.00	-0-	1,300.00
SUBTOTAL	1,300.00	-0-	1,300.00
-Local City Attorneys			
-Bridge City	9,614.12	935.00	8,679.12
-Groves	16,171.64	-0-	16,171.64
-Nederland	32,000.15	2,528.39	29,471.76
Port Arthur	2,605.85	-0-	2,605.85

-Port Neches	23,135.08	63.79	23,071.29
-Rose City	7,288.75	-0-	7,288.75
Vidor & Bevil Oaks	14,610.42	-0-	14,610.42
SUBTOTAL	105,426.01	3,527.18	101,898.83
Coalition Expenses			
-Boyle			
-Jansen	$ 155,560.22	$ -0-	$ 155,560.22
-Whelan	18,749.74	-0-	18,749.74
-Mabry	3,046.29	3,046.29	-0-
-Rehearing & Appeal	2,150.00	-0-	2,150.00
SUBTOTAL	40,000.00	-0-	40,000.00
-Public Parties	219,506.25	3,046.29	216,459.96
-OKA			
-KEA	269,085.00	124,197.00	170,341.75 [3]
-TAC	25,453.75		
-MHB	77,475.00	-0-	77,475.00
SUBTOTAL	83,966.50	-0-	83,966.50
-Staff Consultants	455,980.25	124,197.00	331,783.25
-Decision Management Services	24,145.45	-0-	24,145.45
-QED Research	20,965.97	-0-	20,965.97
SUBTOTAL	45,111.42	-0-	45,111.42
TOTAL	12,924,270.13	6,981,853.50	5,942,416.63

[3] For calculation of amount, see Page 9 of 10 [App. 96a].

Sources: GSU Exhibit No. 286A, Seq. Nos. 222290 (Amended), 222291, and 222295; GSU Exhibit No. 284A, Seq. No. 214640; GSU Exhibit No. 286C, Seq. No. 222369; CAUR Exhibit No. 153; CAUR Exhibit No. 162; PPC Exhibit No. 17; Cities Exhibit No. 98; Cities Exhibit No. 100; Neches Exhibit Nos. 1-3; Rose City Exhibit No. 1; Bridge City Exhibit No. 1; Vidor Exhibit Nos. 1-1A; Nederland Exhibit No. 1; and Groves Exhibit No. 1.

Method of Calculating Allowed Rate Base Expenses for GSU Outside Consultants and Attorneys

1. Take the total amount of expenses spent by GSU in Louisiana and Texas for Outside Consultants and Attorneys.

Texas:	Consultants	$2,569,366.09
	Attorneys	5,169,566.36
La:	Consultants	805,147.81
	Attorneys	657,435.06
		$9,201,515.32

2. Allocate this total by the Power Pool Percentage for Texas developed in Docket No. 7195 by GSU—40.7725%. (Vol. 1 of 11—Seq. #214640).

$9,201,515.32 x 40.7725% = $3,751,687.83

Therefore, total expenses for GSU Outside Consultants and Attorneys Allocable to Texas = $3,751,687.83

Sources: Staff Exhibit No. 77; GSU Exhibit No. 286A, Seq. No. 222295; GSU Exhibit No. 284A, Seq. No. 214640.

Method of Calculating Allowed Rate Case Expenses for OKA and KEA Consultants for Public Parties Committee

1. Take the total amount of expenses spent by Intervenors who hired O'Brien Krietzberg & Associates (OKA) and Komanoff Energy Associates (KEA).

Texas:	OKA	$285,500.45
	KEA	25,369.35
La:	OKA	82,025.13
	KEA	24,890.95
		$417,785.88

2. Allocate this total by the Power Pool Percentage for Texas developed in Docket No. 7195 by GSU—40.7725%. (Vol. 1 of 11—Seq. #214640).

$417,785.88 x 40.7725% = $170,341.75

Therefore, total expenses allowed for OKA and KEA allocable to Texas

= $170,341.75

Sources: Staff Exhibit No. 77; GSU Exhibit No. 284A, Seq. No. 214640.

SYNOPSIS OF DECISION MADE
FINAL ORDERS MEETING—MAY 8, 1988

(Re: Rate Case Expenses)

	Additional Amount Requested	Additional Amount Allowed	Total Allowed
Butler & Casstevens	8,441.45	8,441.45	8,441.45
Boyle	14,578.64	14,578.64	14,578.64

	Amount Requested	Amount Disallowed	Amount Allowed
Bridge City	9,614.12	935.00	8,679.12
Groves	16,171.64	-0-	16,171.64
Nederland	32,000.15	2,528.39	29,471.76
Port Arthur	2,605.85	-0-	2,605.85
Port Neches	23,135.08	63.79	23,071.29
Rose City	7,288.75	-0-	7,288.75
Vidor & Bevil Oaks	14,610.42	-0-	14,610.42

Detail of Disallowed Expenses

Bridge City	11/17/86—2.15 hrs. at $100/hr. =	$215
	11/19/86—1.50 hrs. at $100/hr. =	150
	11/21/86— .20 hrs. at $100/hr. =	20
	11/24/86— .20 hrs. at $100/hr. =	20
	12/10/86— .20 hrs. at $100/hr. =	20
	01/27/87— .20 hrs. at $100/hr. =	20
	03/31/87—2.95 hrs. at $100/hr. =	295
	04/10/87— .30 hrs. at $100/hr. =	30
	04/13/87— .65 hrs. at $100/hr. =	65
	05/04/87— .50 hrs. at $100/hr. =	50
	01/12/88— .50 hrs. at $100/hr. =	50
		$935
Nederland	City Council (Expenses) @ $ 945.00	
	City Manager (Expenses) @ $1,583.39 =	$2,528.39
Port Neches	1/11/87—City Council Meals =	$ 63.79

SCHEDULE I

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

REVENUE REQUIREMENT

Description	(Column 1) Test Year Per Books	(Column 2) Company Adjustments to Test Year	(Column 3) Company Requested Test Year	(Column 4) Commission Adjustments to Request	(Column 5) Commission Order
Purchased Power	$ 175,710,099	$ 15,753,225	$ 191,463,324	$ 38,619,968	$ 230,083,292
Fuel	690,504,390	(193,520,309)	496,984,081	(127,149,736)	369,834,345
Operations and Maintenance	224,809,753	(496,141,840)	(271,332,087)	548,784,923	277,452,836
Decommissioning Expense	0	2,579,000	2,579,000	(335,981)	2,243,019
Depreciation	100,623,983	54,875,683	155,499,666	(28,822,206)	126,677,460
Amortization	4,947,264	83,936,746	88,884,010	(89,949,786)	(1,065,776)
Interest on Customers Deposits	0	1,082,680	1,082,680	(191,586)	891,094
Taxes Other Than Income Taxes	76,797,706	8,823,409	85,621,115	(4,235,787)	81,385,328
State Income Taxes	(9,102,122)	32,340,390	23,238,268	0	23,238,268
Federal Income Taxes	24,082,463	192,726,556	216,809,019	(117,660,580)	20,067,405
Return	336,955,989	310,824,508	647,780,497	(254,763,330)	393,017,167
Flowback of Excess DFIT (A)	0	0	0	(3,119,461)	(3,119,461)
Revenue Requirement	$1,625,329,525	$ 13,280,048	$1,638,609,573	$ (38,823,562)	$1,520,704,978
Less: Rate Case Expenses Included in Operations and Maintenance Expense					(2,971,208)
Net Revenue Requirement					1,517,733,770

(A) Non-Depreciation Items Only, Depreciation Items Are Included in the Net Deprec Adjustment Shown on Schedule VII

SCHEDULE II

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

OPERATIONS AND MAINTENANCE (EXCLUDING FUEL AND PURCHASED POWER)

Description	(Column 1) Test Year Per Books	(Column 2) Company Adjustments to Test Year	(Column 3) Company Requested Test Year	(Column 4) Commission Adjustments to Request	(Column 5) Commission Order
O&M Not Adjusted	$ 63,800,352	$ 0	$ 63,800,352	$ 0	$ 63,800,352
Reclassification and Eliminations	0	(39,151)	(39,151)	0	(39,151)
River Bend Unit One in Service Costs	0	54,709,000	54,709,000	0	54,709,000
Fuel and Purchase Power	0	(1,591,467)	(1,591,467)	1,591,467	0
Payroll	104,373,072	20,784,948	125,158,020	(10,512,750)	114,645,270
Employee Benefits	25,066,930	2,087,370	27,154,300	(5,084,531)	22,069,769
Transfer of Nelson Seven to Steam Dept	99,028	(99,028)	0	0	0
Nelson One and Two Joint Venture	3,003,595	(3,003,595)	0	0	0
Adj to Storm Damage Reserve	2,504,000	1,656,630	4,160,630	(333,288)	3,827,342
Pymts to Public Parties Committee	0	500,000	500,000	(500,000)	0
Insurance Expense	7,335,738	7,573,986	14,909,724	326,815	15,236,539
Rate Case Expense	7,172,993	(469,624)	6,703,369	(3,732,161)	2,971,208
Safety Achievement Expense	182,560	(182,560)	0	0	0
Airplane Expense and Pilots Salaries	131,044	(131,044)	0	0	0
Dues	675,638	(201,151)	474,487	187	474,674

SCHEDULE II—Continued

Description	(Column 1) Test Year Per Books	(Column 2) Company Adjustments to Test Year	(Column 3) Company Requested Test Year	(Column 4) Commission Adjustments to Request	(Column 5) Commission Order
Lt Storage of Neches and La Station	2,859,465	(517,215)	2,342,250	0	2,342,250
Edison Plaza Lease	2,949,800	3,618,745	6,568,545	(340,261)	6,228,284
Project Save Cash	0	(6,530,455)	(6,530,455)	0	(6,530,455)
Difference Due to Allocations	0	(560,178)	(560,178)	532,025	(28,153)
Rate Moderation Plan	0	(574,550,000)	(574,550,000)	574,550,000	0
Incentive Plans	811,951	0	811,951	(587,596)	224,355
Reimbursements From CEPCO	0	0	0	(5,970,301)	(5,970,301)
Conservation Expense	176,853	0	176,853	(78,686)	98,167
Gain on Disp of Property	(191,228)	191,228	0	0	0
Advertising Expense	0	0	0	(754,385)	(754,385)
Uncollectible Expense	3,857,962	611,721	4,469,683	(321,612)	4,148,071
Total Operations and Maintenance	$224,809,753	$(496,141,840)	$(271,332,087)	$548,784,923	$277,452,836

SCHEDULE III

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

SUMMARY OF TAXES OTHER THAN INCOME TAXES

Description	(Column 1) Test Year Per Books	(Column 2) Company Adjustments to Test Year	(Column 3) Company Requested Test Year	(Column 4) Commission Adjustments to Request	(Column 5) Commission Order
Texas Ad Valorem Taxes	$14,348,553	$ 637,050	$14,985,603	$ 0	$14,985,603
Other State's Ad Valorem Taxes	8,799,815	1,716,700	10,516,515	0	10,516,515
Payroll Taxes	7,347,633	1,013,867	8,361,500	0	8,361,500
Other Non Revenue Related Taxes	15,705,350	827,852	16,533,202	1,700,855	18,234,057
Non Revenue Related Taxes	$46,201,351	$4,195,469	$50,396,820	$ 1,700,855	$52,097,675
Texas PUC Assessment	$ 1,207,511	$ 304,775	$ 1,512,286	$ (356,424)	$ 1,155,862
Texas State Gross Receipts	5,265,591	1,329,031	6,594,622	(1,554,257)	5,040,365
Texas Local Gross Receipts	10,836,779	2,735,194	13,571,973	(3,198,717)	10,373,256
Other State's Gross Receipts Tax	13,286,474	258,940	13,545,414	(827,244)	12,718,170
Revenue Related Taxes Other Than Income Taxes	$30,596,355	$4,627,940	$35,224,295	$(5,936,642)	$29,287,653
Summary of Other Taxes Other Than Income Taxes					
Non Revenue Related Taxes	$46,201,351	$4,195,469	$50,396,820	$ 1,700,855	$52,097,675
Revenue Related Taxes	30,596,355	4,627,940	35,224,295	(5,936,642)	29,287,653
Total Taxes Other Than Income Taxes	$76,797,706	$8,823,409	$85,621,115	$(4,235,787)	$81,385,328

SCHEDULE IV

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

INVESTED CAPITAL

Description	(Column 1) Test Year Per Books	(Column 2) Company Adjustments to Test Year	(Column 3) Company Requested Test Year	(Column 4) Commission Adjustments to Request	(Column 5) Commission Order
Plant in Service	$ 3,156,648,184	$ 2,872,013,911	$ 6,028,662,095	$(1,450,564,387)	$ 4,578,097,708
Accumulated Depreciation	(1,052,887,490)	(101,580,176)	(1,154,467,666)	(8,090,242)	(1,162,557,908)
Net Plant in Service	2,103,760,694	2,770,433,735	4,874,194,429	(1,458,654,629)	3,415,539,800
Construction Work in Progress	2,940,936,703	(2,940,936,703)	0	0	0
Property Held for Future Use	146,342,244	(28,149,994)	118,192,250	(91,292,258)	26,899,992
Working Cash Allowance	10,276,474	(14,069,506)	(3,793,032)	(12,134,169)	(15,927,201)
Materials and Supplies	7,061,692	(155,950)	6,905,742	(640,264)	6,265,478
Prepayments	13,501,108	(1,526)	13,499,582	(51,876)	13,447,706
Fuel Inventory	42,034,397	0	42,034,397	(17,702,320)	24,332,077
Deferred Revenue Accounting Order	0	572,398,000	572,398,000	(159,954,372)	412,443,628
Deferred Revenue Rate Moderation	0	287,275,000	287,275,000	(287,275,000)	0
Deferred Sales Tax Coal Cars	805,463	0	805,463	0	805,463
Unamortized Losses	0	345,565	345,565	(345,565)	0

SCHEDULE IV—Continued

Deferred Federal Income Taxes	(386,561,793)	(232,323,617)	(618,885,410)	190,645,065	(428,240,345)
Pre 1971 Investment Tax Credits	(119,411,856)	114,841,896	(4,569,960)	0	(4,569,960)
Customers Deposits	(15,337,154)	0	(15,337,154)	0	(15,337,154)
Property Insurance Reserve	(3,848,645)	0	(3,848,645)	0	(3,848,645)
Injuries and Damages Reserve	(890,098)	0	(890,098)	0	(890,098)
Early Retirement	(8,312,692)	80,989	(8,231,703)	8,231,703	0
Safety Achievement Reserve	(329,015)	329,015	0	(230,310)	(230,310)
Deferred MICP Reserve	0	(33,635)	(33,635)	0	(33,635)
Contra AFUDC Nuclear Fuel	(4,774,401)	795,734	(3,978,667)	(795,734)	(4,774,401)
Coal Car Maintenance Reserve	(2,276,829)	0	(2,276,829)	0	(2,276,829)
Unclaimed Dividends	(111,090)	12	(111,078)	0	(111,078)
Total Invested Capital	$ 4,722,865,202	$ 530,829,015	$ 5,253,694,217	$(1,830,199,729)	$ 3,423,494,488
Rate of Return			0.123300	-0.008500	0.114800
Return			$ 647,780,497	$ (254,763,330)	$ 393,017,167

SCHEDULE V

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

FEDERAL INCOME TAXES—TAX METHOD 2

Description	Commission Order
Revenue Requirement	$1,520,704,977
Less: O & M Expenses	(878,261,567)
Depreciation Expenses	(128,920,479)
Amortization Expense	1,065,776
Taxes Other Than Income	(81,385,328)
Interest Exp	(293,372,602)
Rate Moderation	0
LA State Taxes	(23,238,268)
Toxic Waste Disp Tax	(48,150)
Book Income Before Tax	116,544,359
Less: Permanent Differences	(46,269,859)
Timing Differences	(106,570,983)
Taxable Income	(36,296,483)
Times: Tax Rate	34%
Current Income Tax Before Credits	(12,340,804)

The Calculation of Federal Income Taxes (F.I.T.) is Detailed on Schedules V, VI and VII. Federal Income Taxes were Calculated Using the Alternative Minimum Tax Methodology as Ordered by the Commission. The Methodology Employed in This F.I.T. Calculation is the Same as that Used by the Company in Carrying out the Commission Order of March 10, 1988.

SCHEDULE VI

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

CALCULATION OF ALTERNATIVE MINIMUM TAX

Description	Commission Order
Reg Fed Tax Inc Before SIT & NOL	($38,667,721)
Reg Fed NOL Carryfwd Beg Year	408,628,445
Reg Fed NOL Carryfwd Utilized	0
Reg Federal Tax Inc Before SIT	(38,667,721)
Louisiana Income Tax:	
La Tax Inc Bef FIT & La NOL Deduc	($24,662,668)
La Fit Deduct Apportioned	2,227,025
La Tax Inc After FIT & Before NOL	(26,889,693)
La NOL Carryfwd Beg Year	76,023,897
La NOL Carryfwd Utilized	0
La Taxable Income	(26,889,693)
Tax Effect of La NOL	(2,151,175)
La State Income Tax	0
Regular Federal Income Tax:	
Regular Federal Taxable Income	($38,667,721)
Tax Effect Regular Federal NOL	(13,147,025)
Regular Federal Income Tax	0
Pre-1987 Deprec Preference Item:	
Tax Pref Item-Depr Pre-1987 Prop	$2,421,952
Alternative Tax Nol Carryfwd:	
Pre-1987 NOL Carryfwd	$116,663,603
Post-1986 NOL Carryfwd	(99,845,194)
Hotal NOL Carryforward	16,818,409
Superfund Clean-Up Fee (0.12% of Amti)	
Toxic Waste Disp Add-On Tax	48,150

SCHEDULE VI—Continued

Description	Commission Order
Pre-Tax Book Income	$116,544,359
Burp Adjustment	76,419,139
Taxable Income for Amti	(36,293,919)
Amti Before N.O.L. Deduction	40,125,220
Alt Min NOL Deduct Limitation	36,112,698
Alt Min NOL Deduction	16,818,409
Alternative Min Tax Income	23,306,811
Tentative Alternative Min Tax	4,661,362
Net Regular Tax Liability	$0
Investment Tax Credit Utilization:	
Allowable Net Regular Tax Liab	$0
Prelim Alt Min Tax 75% ITC Limit	0
Lesser of N.R.T.L. or ITC Limit	0
Prelim Alt Min Tax 25% ITC Limit	1,165,341
Fed Inc Tax Before ITC	4,661,362
ITC Carryfwd, Beginning of Year	252,191,516
Lesser of 25% ITC or 90% Cryfwd	1,165,341
ITC Utilization Limitation	1,165,341
ITC Utilized	1,165,341
Federal Tax Liab After ITC	$3,496,021
Minimum Tax Credit Utilization:	
Minimum Tax Credit Generated	$4,661,362
Beg Year Min Tax Credit Carryfwd	0
Min Tax Credit Utilization Limit	0
Minimum Tax Credit Utilized	0
Net Federal Tax Liability	$3,496,021

SCHEDULE VII

PUBLIC UTILITY COMMISSION OF TEXAS

GULF STATES UTILITIES—DOCKET 7195

SUMMARY OF FEDERAL INCOME TAXES ALLOWABLE

Description	Commission Order
Federal Income Taxes	
Current	
Regular Income Tax Liability	$0
Excess of Amt Over Regular Tax	4,661,362
Investment Tax Credits Utilized	(1,165,341)
Total Current Tax Liability	$3,496,021
Deferred	
Net Deprec Deferred Taxes	$50,441,970
Flowback of Excess Dfit [A]	(2,094,819)
N.O.L. Deferred Taxes	(13,147,025)
Amort of Non-Depr Dfit @ 34%	(7,274,407)
Current Deferral (Non-Depr)	(4,361,590)
Deferred Minimum Tax Credit	(4,661,362)
Net Deferred Income Taxes	$18,902,767
Investment Tax Credits	
Investment Tax Credits Utilized	$1,165,341
Amortization of Deferred ITC	(3,544,874)
Net Investment Tax Credits	(2,379,533)
Toxic Waste Disposal Add-On Tax	$48,150
Tot Federal Income Taxes Allowed	$20,067,405
State Income Taxes	
Current	($2,371,238)
Deferred	25,609,506
Total State Income Taxes Allowed	$23,238,268

[A] Excess Deferred Federal Income Taxes Related to Depreciation Items are Being Flowed Back to Ratepayers Over the Remaining Life of the Assets. See Exhibit 5, in Staff Accountant Layne McKinney's Direct Testimony Dated March, 1987 for Calculation.

SCHEDULE VIII
Examiner

Gulf States Utilities
Docket No. 7195

Capital Structure
and
Cost of Capital

Component	Amount (000s)	Capital Ratio	Component Cost	Weighted Avg Cost
Common Equity	$1,826,520	35.15%	13.00%	4.57%
Preferred and Preference Stock	564,008	10.85%	10.99%	1.19%
Long-Term Debt	2,805,564	53.99%	10.59%	5.72%
Total	$5,196,092	100.00%		11.48%

APPENDIX H

PUBLIC UTILITY COMMISSION OF TEXAS

Docket Nos. 7195 and 6755

APPLICATION OF GULF STATES UTILITIES COMPANY FOR AUTHORITY TO CHANGE RATES

INQUIRY OF THE PUBLIC UTILITY COMMISSION OF TEXAS INTO THE PRUDENCE AND EFFICIENCY OF THE PLANNING AND MANAGEMENT OF THE RIVER BEND NUCLEAR GENERATING STATION

EXAMINERS' REPORT*

[December 7, 1987]

I. *Procedural History*

On February 19, 1986, the Commission's general counsel filed a petition of inquiry into the prudence and efficiency of the planning and management of the construction of the River Bend Nuclear Generating Station (River Bend). The petition of inquiry was assigned Docket No. 6755.

On November 18, 1986, Gulf States Utilities Company (GSU or the company) filed with the Commission an application for authority to increase its electric rates in all unincorporated areas in which it serves and in those incorporated areas which have ceded jurisdiction to this Commission. Virtually identical filings were contemporaneously made with all other Texas regulatory authori-

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* [Excerpts of the Examiners Report are reproduced in this appendix].

ties exercising original rate jurisdiction over the company. The filings included a request for emergency interim rate relief. The company's rate filing with this Commission was assigned Docket No. 7195. The effect of the proposed changes, if implemented system-wide, would be an increase of $153,756,559 or 28.1 percent over adjusted test year revenues. The requested interim rates would have generated a revenue increase of $91,705,010 or 16.8 percent over adjusted test year revenues.

The $153,756,559 rate increase request was due primarily to the inclusion of revenue requirements related to GSU's River Bend Nuclear Generating Station (River Bend) in cost-of-service. The company did not propose to recover the entirety of its River Bend related costs in this docket, however. Instead it proposed a phase-in of those costs under a rate moderation plan involving three years of revenue deferrals, capitalization of the deferred revenues, and recovery of the deferred revenues over the subsequent five-year period. Inclusion of all River Bend-related revenues in this first year request would have produced a proposed Texas retail rate increase of approximately $359.9 million.

Docket Nos. 6755 and 7195 were consolidated by order of the undersigned examiners issued on December 9, 1986.

GSU published notice of its proposed rate schedules once each week for four consecutive weeks in newspapers of general circulation in each Texas county containing territory affected by the proposed change, as required by PURA Section 43 of the Public Utility Regulatory Act (PURA or the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987) and P.U.C. PROC. R. 21.22. The publishers' affidavits certifying publication were filed on February 23, 1987.

Pursuant to Sections 17 and 26 of the Act, GSU appealed the ratemaking ordinances of the following municipalities retaining original ratemaking jurisdiction:

Anahuac, Beaumont, Bremond, Bridge City, Bevil Oaks, Cleveland, Chester, Corrigan, Colmesneil, Crystal Beach, Cut-N-Shoot, Conroe, China, Devers, Groves, Huntsville, Houston, Kountz, Lumberton, Madisonville, Montgomery, Nederland, Nome, New Waverly, Normangee, Orange, Panorama Village, Pine Forest, Pinehurst, Port Neches, Port Arthur, Roman Forest, Rose Hill Acres, Rose City, Shenandoah, Shepherd, Sour Lake, Silsbee, Somerville, Trinity, Vidor, West Orange, Willis, Woodloch and Woodville.

A roster of the parties of record and their respective counsel of record in this proceeding is attached to this Report as Examiners' Exhibit No. 1. Attached as Examiners' Exhibit No. 2 is a table reflecting the caption and date of issuance of each examiners' order issued in this docket, whether or not the order was appealed, and the Commission's action, if any, on the appeal.

Prehearing conferences were conducted in this proceeding on December 8, 1986, December 18, 1986, January 5, 1987, January 9, 1987, February 2, 1987, and March 13, 1987, for the purpose of ruling on pending motions and to address scheduling issues, discovery disputes and other procedural matters.

A hearing on the merits of the request for interim rate relief was convened on January 12, 1987 and adjourned on February 3, 1987. The interim hearing was presided over by Mr. Phillip A. Holder, Secretary of the Commission, and Commissioners Peggy Rosson, Dennis L. Thomas and Jo Campbell. Interim rates were granted by Commission order dated February 5, 1987. Implementation of the interim rates was approved by Commission order dated April 7, 1987. Interim rates have been in effect since that date, subject to rescission, modification or refund by the Commission.

The hearing on the merits of the permanent rate request commenced on March 23, 1987 and ended on

September 15, 1987. The hearing was divided into four phases, as follows: 1) Non-River Bend revenue requirement issues, presided over by Examiner Charles J. Smaistrla; 2) Rate of return issues, jointly presided over by Mr. Smaistrla and Administrative Law Judge Henry D. Card; 3) River Bend prudence issues, presided over by Judge Card; and 4) Cost allocation and rate design issues, presided over by Administrative Law Judge Mark W. Smith.

By examiners' order dated November 19, 1986, implementation of the proposed rate schedule was suspended for the statutory period of 150 days from the otherwise effective date of December 23, 1986, until May 22, 1987. There were 118 days of actual hearing on the merits of the permanent rate request, two stipulated days of hearing on the permanent rate request, 10 days of evidentiary hearing on the merits on the interim rate request and two additional days (January 29 and February 3, 1987) on which the hearing on the merits of the interim request was convened to address procedural matters and to deliberate and render a decision on the interim rate request, for a total of 132 days of hearing. Accordingly, by operation of Section 43(d) of the Act, the period of suspension has been extended for a total of 234 calendar days, from May 22, 1987, until January 11, 1988. Objections, if any, to the examiners' calculation of the period of suspension, should be raised through written exceptions to this Report.

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VI. *River Bend Issues*

• • • •

D. *Prudence of the Decision to Restart River Bend*

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8. Examiners' Recommendation

The examiners conclude that the 1978-79 decision to restart River Bend was prudent. The decision was within

the select range of options which a reasonable utility manager would have chosen given the information available at the time. The examiners find that the decision was based primarily upon the company's load growth and its fear of a substantial write-off if River Bend were cancelled. The company did believe, however, that nuclear generation would be cheaper than coal-fired generation in the long-term. They agree with intervenors that in making that decision GSU abandoned the financial goals set forth in the 1977 "Planning for Its Growth" study, but also agree that those goals were no longer tenable in light of the pressing need for additional capacity.

The examiners do not find that GSU should have ordered the DCE prepared before deciding to restart River Bend. The 1977 estimate was considered a good one and anticipated plant costs had been reviewed during the rebidding analysis. In late 1978 and early 1979, GSU had sufficient information to reach a decision and should reasonably have expected the plant to cost somewhat less than $1.7 billion, which was the high end of the estimates presented to the Board in February 1979.

The examiners do find that GSU was imprudent in relying upon S&W's projected 50-month schedule, although it could legitimately have expected some schedule compression and some savings from implementation of the NPCSA and use of rolling 4-10's. GSU should have anticipated some regulatory change, though not to the extent suggested by the intervenors. OKA also identified some omissions which should have been put in the DCE. The examiners find that a DCE of approximately $1.980-2.030 billion would have been appropriate. To that the company should have added, for financial planning purposes, an informal contingency of 15 percent of to-go costs, for an outside cost of $2.273 billion.

The examiners agree with the intervenors that GSU did not seriously reevaluate the decision to restart River Bend after receiving the DCE. That failure is not sur-

prising, since the actual DCE was within the cost range which GSU had already considered. A reevaluation at the $1.98-2.030 billion level or even at the $2.273 billion level, however, would not necessarily have impelled a prudent manager to decide to cancel or defer the plant.

Dr. Andersen's optimal expansion path, based upon the displacement of gas-fired generation, would have been a reasonable course for GSU to have taken. That fact does not render the decision to continue with River Bend imprudent, however, especially when one considers such factors as fuel diversity, the possible financial impact of River Bend cancellation, and uncertainties attendant to coal-fired generation itself.

Finally, the examiners reject the arguments that GSU's financial condition should have precluded construction of River Bend, that uncertain load growth should have foreclosed the construction of nuclear generation, and that the CEPCO buyback agreement was imprudent.

a. *Reasons for the restart decision.* In determining the reasons for the restart decision, the examiners have relied primarily on three contemporaneous documents: Mr. Crawford's July 3, 1987, letter calling the August 1 meeting; the minutes of the August 1 meeting itself; and some notes taken at the August 1 meeting (OPC Exs. 37, 38, and 39). The first two, which are relatively short, are attached to this report as Examiners' Exhibit Nos. 5 and 6. The examiners have also relied to a lesser extent on the testimony and cross-examination of Mr. Lee, who was an active participant in the decision.

The minutes and notes of the August 1, 1978, meeting make it clear that the driving forces behind the decision to restart River Bend were the resurgence in load growth GSU experienced in 1977 and 1978 and its projected future growth of approximately 6 percent annually. During 1977 and 1978, River Bend had been on hold due to financial considerations and reduced load growth. By the

August 1 meeting, however, it seemed obvious that additional generating capacity would be necessary. Mr. Lee indicated at that time that the company's load had increased by 495 MW in 1977 and 450 MW in 1978, and that annual growth had exceeded 5 percent in every year except 1953, 1974, 1975, and 1976. GSU Ex. 39 at 3-4.

It is also clear that because of its high capital cost GSU would nevertheless have abandoned River Bend in favor of another form of generation, if not for the approximately $400 million dollars in sunken and cancellation costs involved in that course of action. The minutes and notes of the August 1 meeting show that the consequences of a write-off of those costs were discussed at great length. Using rough figures, Mr. Robert Jackson, then GSU's chief financial officer, estimated the financial consequences of cancellation. The United States would have shouldered about one-half of the approximately $400 million through federal income tax reductions. A write-off of the remaining $200 million, if spread out over ten years, would have equaled about 40 percent of GSU's total earnings. That scenario assumed no help from the regulatory authorities. The officials present at the meeting expressed serious concern about the impact of such a write-off on the company's shareholders and on its ability to finance other necessary construction. OPC Ex. 39 at 6-7, 14-15, 17-18, and 23.

The third dominant consideration was the matter of financing. GSU found itself in a serious dilemma. Management did not know exactly how it would go about financing the completion of River Bend, particularly without participation by other utilities or significant rate relief from Louisiana, relief which then seemed unlikely. See OPC Ex. 39 at 12A; Tr. Vol. 57 at 8928-29 (Lee cross). On the other hand, if it scrapped River Bend, GSU would still have to finance a large construction program, perhaps after taking a significant write-off. Its chief financial officer was of the opinion that cancelling

the plant would stymie GSU's ability to raise outside funds. OPC Ex. 39 at 17; Tr. Vol. 57 at 8951-52, 9005 (Lee cross).

Two points emphasized by Mr. Lee—fuel diversity and the economic advantages of nuclear over coal-fired generation—appear to have been of little consequence in the discussions. The examiners could find no reference at all to fuel diversity, and only a passing one to the long-term economic benefits of nuclear power. OPC Ex. 39 at 16. That is not to say that GSU did not believe that River Bend would diversify its fuel mix or that it would be cheaper than coal over the life of the plant, but merely that those factors—especially fuel diversity—did not weigh heavily in the deliberations. That interpretation is borne out by the fact that after the meeting Mr. Crawford continued, without success, to attempt to sell River Bend—to Taiwan, Japan, Korea, or Iran. CAUR Ex. 109-111. To the examiners those attempts imply that GSU was not wedded to River Bend by its long-term economics or its contributions to fuel diversity.

Nor was continued deferral, which would have at least postponed any write-off, seriously considered. According to Mr. Lee,

> Our basic assumption was that we either had to do one of two things. Because of the rapid rise in cost of generation, we either had to build it or cancel it and do it shortly.
>
> Q: That's the consideration you had in 1978?
>
> A: Yes.
>
> Q: And that's the reason why you did not consider the deferral scenario?
>
> A: That's correct.

Tr. Vol. 57 at 9008.

The upshot of the August 1, 1978, meeting was set forth in the minutes:

1. The chance of selling the unit to another utility is very remote. Walking away from River Bend No. 1, at a cost of $300-$400 million, is impractical, since such a sum cannot be written off against either the stockholders or ratepayers on a viable basis. The unit cannot reasonably be moved to Texas since doing so would involve forfeiting the construction permit and starting over. Three years and an additional $300 million would probably be the result of obtaining a new construction permit for the Blue Hills site.

2. The only realistic course open to use apparently is to build the unit at River Bend as fast as possible, thus reducing the financial burden as much as possible. Each year's delay escalates the eventual cost by approximately $100 million.

3. In addition to shortening the construction time, perhaps by going to two shifts, every effort must be made to mitigate the financial impact on the company.

Although a final decision was not reached at that time, that course of action was presented to and approved by the Board in February 1979. Between August 1 and the February Board meeting, Louisiana had granted more rate relief than expected and the handshake agreement with CEPCO had been reached, easing GSU's financial concerns somewhat.

The examiners find that GSU's load growth concerns were legitimate. As testified by Mr. Zarnikau and Dr. Pflaum, GSU's forecasting was flawed in its failure to account for the effects of price elasticity. Mr. Zarnikau agreed, that projected growth of 3-4 percent would have been appropriate and that GSU could not have predicted the disastrous slump in its service area's economy in the early 1980's. In fact, no one testified that GSU did not reasonably predict a need for new generating capacity.

GSU's predicted load growth was consistent with its historical pattern and with the predictions of neighboring utilities. The Fuel Use Act also required new capacity.

The other two factors stressed above—the fear of a large write-off and difficulties in financing—would appear to argue against the prudence of the restart decision. The former suggests that GSU was merely looking out for "number one", its shareholders, regardless of the economic wisdom of building the plant. The latter suggests that GSU was willing to gamble the company to protect that investment. The examiners do not interpret them that way, however. Although the effect on stockholders was important, management seemed particularly concerned about how to finance any significant construction in the face of a potentially massive write-off. That concern was not unfounded, even though GSU did not have a specific write-off number in mind above which its financial ability would be impaired. Tr. Vol. 57 at 9005 (Lee cross). Less than half of the total would have been recovered from tax savings. Certainly some recovery might reasonably have been expected in Texas, but that was not assured. The potential write-off of River Bend would have been the largest theretofore experienced for a nuclear project. Mr. Osbon testified that the first significant plant abandonment (over $50 million) was of Surry Units 3 and 4 in March 1979 at a cost of $66 million. The potential consequences of cancellation of a plant with such a large amount invested in it should not have been ignored. And, as GSU pointed out, recovery of River Bend costs from ratepayers would have meant that customers were paying for a useless investment.

OPC correctly pointed out that deferral of the plant would not have triggered a write-off. Its contention in that regard is that GSU should have continued to defer River Bend and first built its scheduled coal plants to meet its expected load. In retrospect that course would have been wiser. The examiners cannot find GSU im-

prudent, however, in deciding either to build or cancel the plant in 1978-79. In the face of load growth, a legitimate need for additional capacity, and escalating nuclear costs, the examiners do not find that procrastination on the most important issue facing the company was the only prudent course.

GSU was not sure how it would finance River Bend. That does not mean that it thought the plant would bring it to the brink of financial disaster. Mr. Jackson had informed management that the plant could be financed. Tr. Vol. 57 at 8929-30 (Lee cross). Obviously rate increases would be necessary, as clearly shown by the Restart Study. But, as Mr. Lee pointed out, a utility does not have the rate base to finance any large capital intensive project when that project is begun. Tr. Vol. 57 at 8920. GSU was not imprudent in expecting some rate relief, especially in Texas at that time. There is nothing wrong with proceeding in that fashion, provided that the project is necessary, well-managed, and reasonably expected to be economically beneficial to customers. The examiners also note Mr. McBride's calculation of $350 million in additional first mortgage bond issuance capacity (at Dr. Andersen's more reasonable 9.5 percent interest rate) above the $1.3 billion figure used in the Restart Study, GSU Ex. 218; Tr. Vol. 95 at 14900 et. seq. (McBride cross). That amount, plus the $1.3 billion, is less than the $1.729 billion DCE, but it does not include participation or other sources of financing. Tr. Vol. 96 at 15069 (McBride cross). Mr. Donnelly's testimony as to other methods used to assure that River Bend could be financed was convincing.

The examiners also find that GSU was reasonable in its belief that participation by CEPCO was forthcoming. The two companies had been negotiating for years—at the August 1 meeting Mr. Lee observed that CEPCO expressed an interest as early as 1974 or 1975, and that they had not faltered. OPC Ex. 39 at 10. The two com-

panies reached a handshake agreement in January 1979 and a signed agreement in August of that year. All problems had generally been worked out by February 1979. GSU Ex. 90. Although participation was subject to the approval of the REA, and approval had not been guaranteed, GSU had no reason to expect difficulties on that score. A February 1978 letter from the REA Director for the Southwest area indicated that REA looked upon such arrangements favorably, subject to cooperatives' needs for the resources to be purchased. GSU Ex. 89.

Louisiana's December 1978 rate decision, granting a $22.8 million increase (approximately a third of GSU's request) was unexpected and also improved GSU's financial prospects. It would not have been reasonable for GSU to have placed too much faith on continued rate relief in Louisiana, however, particularly since the Louisiana P.S.C. continued to be rated as one of the "worst" (from a utility's perspective) in the United States. OPC Ex. 73.

With regard to the financing of River Bend, three additional observations must be made. First, intervenors and staff are correct in saying that the 1978 Restart Study, while giving GSU a rough idea of its financing capacity, was deficient. The study used an unreasonably low capital cost figure and did not model the financial consequences of "inadequate" rate relief. In making their decision, management and the Board did consider more realistic capital cost assumptions, however.

Second, the intervenors' and the staff's reliance on GSU's 1977 "Planning for Its Growth" report is woefully misplaced. In that document the company's Strategic Planning Committee advocated that the company sacrifice its commitment to reliable service in order to improve its earnings per share and interest coverage ratios, achieve a "AA" bond rating, and increase its dividends.

> The program we outlined will not be an easy process nor will it be a rapid one. The reduced levels of capital expenditures imposed by the financial constraints will undoubtedly cause problems in the operating area. It may cause restriction of electric investment dedicated to Louisiana and it will probably be necessary and desirable to accept a lower level of service reliability than we have been willing to accept in the past. We view the foregoing as a financial plan for survival—one that has every chance of maintaining our financial integrity and protecting our bond and shareholders.

GSU Ex. 87 (Lee direct test.), Ex. NRL-2 at 28.

> In the past it has been the industry practice to serve all of the load at any cost. In the future, due to financial limitations, we may find ourselves in the position that we cannot afford the luxury of having:
>
> sufficient generation
> adequate transmission
> fuel flexibility
> adequate stand by power from others.

Id. at 53.

> Continuation with previously announced construction plans in light of the Louisiana Public Service Commission's denial of our rate increase application would result in further declines in earnings per share and deterioration of bond coverage ratios, in addition to the continued negative prospect of selling new common stock below book value. To attack this problem, the planning group determined that a maximum allowable annual expenditure rate for construction should be determined that would provide for a turnaround in our financial parameters to re-establish a solid "AA" rating for the company.

Id. at 67.

The examiners have never before seen a document which treated so cavalierly a utility's duty to provide reliable and adequate service. The Louisiana Commission reminded GSU of that duty in its 1978 rate decision. For GSU to have continued pursuing the 1977 Study's goals in 1978-79, in light of the perceived need for new capacity, would have been very irresponsible.

Third, none of the many studies and analyses presented in this docket remotely suggest that GSU would have courted disaster from financing River Bend at any cost level reasonably expected in 1979, given CEPCO's participation. As is discussed below, a high estimate for the plant, including a 15 percent contingency, would have been approximately $2.27 billion in September 1979. That amount is approximately $2.2 billion below the actual cost of River Bend at completion. MHB's highest suggestion, $2.6 billion, is still almost $2 billion below the actual cost. At that cost level participation probably would have been 37 percent, since the REA refused to approve SRG&T's loan guarantee because of River Bend's rising price tag. In that sense, then, financing is a non-issue if one looks at costs which might have been expected in 1979 instead of the actual cost in 1986. Indeed, if River Bend had actually cost $2.6 billion, this docket would probably not have been very controversial, except perhaps on the issue of excess capacity.

As Dr. Pflaum put it,

> Now, in the case of a prudence disallowance, there a utility might have made a bad decision in part, and that's why we're where we're at today. But a lot of other things happened over which they had absolutely no control.
>
> Now, I think GSU made a bad decision to continue with River Bend. But I don't, for a moment, entertain the idea that they would have continued had

they had any inkling that it was going to cost $4.4 billion.

Tr. Vol. 103 at 10675.

b. *The definitive cost estimate.* The examiners find that the DCE generally was professionally and thoroughly prepared, that GSU reasonably monitored S&W's preparation, and that GSU prudently relied upon the DCE. They do find, however, that GSU was imprudent in relying on the 50-month schedule. A more reasonable schedule of approximately 60 months would have added approximately $183 million to the DCE. Foreseeable regulatory changes would have added another $50-100 million, and omissions identified by OKA another $18 million, for an expected cost of River Bend in September 1979 of approximately $1.980-2.030 billion, or $2106-2160/kW. For financial planning, GSU should have added an informal contingency of 15 percent of to-go costs. The outside cost, given unexpected developments and the higher $2.030 billion expected cost, would have been $2.273 billion.

(1) Preparation and monitoring of the DCE. The examiners agree with Mr. Hadzi-Pavlovic that the underestimates in the DCE were not due to poor estimating practices or to the failure of GSU to control S&W. Mr. Schultz' testimony showed that the DCE was prepared according to industry and S&W practice by breaking down the job into its various components and applying effective unit manhour rates. The process was thorough and the rates used realistic. GSU actively monitored S&W's preparation of the estimate and had reason to believe that S&W's forecast was accurate and fairly represented the scope of work to be performed. On June 8, 1978, Dr. Weigand requested further information on the scope of work to be covered by the DCE. Among other questions, Dr. Weigand asked whether the scope satisfied the latest NRC fire protection requirements and whether it encompassed the May 1977 DCE and all accepted MEC's since generated. On August 7, 1979, Dr. Weigand

informed S&W that GSU wanted escalation broken down into component parts to facilitate the tracking of costs. On August 18, GSU questioned S&W's escalation rates, which were subsequently revised upward. In September, Dr. Weigand requested additional information on escalation on changes to the projec' since the DCE cut-off date. He also requested a reconciliation of manhours between the DCE and MCC's approved since May 1977. In October, S&W provided GSU with an estimate of known impacts to the project of approximately $34 million since the cut-off date. On October 10, GSU asked a number of questions prompted by S&W's presentation of the DCE. On October 24, S&W provided additional information as to its headquarters costs, after being requested to do so. On October 26, also at GSU's request, S&W provided an estimate of probable levels of confidence in various aspects of the DCE. S&W stated that its overall level of confidence was between 90-95 percent. GSU Ex. 59.

On March 6, 1979, GSU set forth the following initial guidelines for preparation of the DCE:

A. 50 month construction schedule (rebar reactor mat 8/1/79 thru fuel load 10/1/83)

B. Incorporate all approved MEC's

C. Incorporate additional work defined by the development of EMS system

D. Unit 2 decoupled

E. Nuclear Stabilization Agreement in effect (single shift 4 rolling 10's)

F. Full visibility on estimated manhours (field manual and non-manual, engineering and design, subcontracts manual and non-manual and home office)

G. Incorporate all additional approved scope of work changes

H. Include escalation as a one line item in the estimate

Given its assumptions, GSU had ample reason to believe in the accuracy of the DCE. Its consultants, MAC, had generally endorsed the accuracy of S&W's previous 1977 estimate. Although a June 1980 letter from Mr. R.H. Townsend to Mr. Curless points to deficiencies in the DCE, it does not show that S&W's estimating process was improper or that GSU had reason to lack confidence in the DCE in 1979. CAUR Ex. 98.

The examiners do not find that GSU was imprudent in its control or monitoring of S&W's preparation of the DCE. GSU had no reason to doubt S&W's ability to provide an accurate estimate or to presume that S&W had underestimated the percentage of engineering complete. Although S&W had not undertaken significant design development during the construction hiatus, it had, according to Mr. Glazar, continued to monitor and incorporate regulatory changes. GSU Ex. 209 (Glazer rebuttal test.) at 14. The 1979 DCE included significant cost increases associated with scope changes and design development. CAUR Ex. 17. The examiners are not convinced that a larger GSU engineering staff or more aggressive monitoring of S&W would have resulted in a more accurate estimate of cost or percentage of engineering complete. The evidence does show a "hands-off" policy toward S&W by GSU. PPC Ex. 10 at 5-34. The evidence also shows, however, that GSU was actively involved in monitoring and questioning the assumptions underlying the DCE. There was a continual interchange of queries and information between Mr. Schultz of S&W and Dr. Weigand of GSU. As Mr. Hadzi-Pavlovic pointed out, all architect-engineers were having trouble estimating costs in that time period. The examiners agree with OKA that EMS was seriously flawed. The system was not prepared for the 50-month construction schedule. More GSU engineers or an earlier audit of EMS would not necessarily have significantly improved the DCE, however.

The best measure of the impact of the supposed absence of engineering controls is an analysis of what items were not included in the DCE but should have been. That information can best be found in the WPCNs and MCCs which OKA analyzed. The examiners have not found serious omissions on S&W's part. The actual costs of many of the items cited by OKA, such as ASME-NF piping requirements and ongoing contract negotiations, were unknown and would appropriately have been covered by a contingency rather than a specific number in the DCE. Moreover, almost $278 million of the $343 million in "omissions" identified by OKA, more than 80 percent, pertained to the 18-month schedule extension or escalation, areas not remotely related to the engineering scope of the project. Much of the remaining $66 million was unrelated to engineering scope as well.

(2) 50-month schedule. One assumption which GSU should have rejected was that the 50-month schedule could be met. That schedule, which was shorter than any theretofore achieved, was 11 months shorter than Bechtel's 61-month rebid proposal, which also used rolling 4-10's. The examiners do not doubt Mr. Traylor's assertion that the 1978 PCE can be used to calculate a 30 percent probability of meeting a 50-month schedule even without rolling 4-10's. GSU did not perform such a probabilistic analysis at the time, however. In fact, it did not perform any independent evaluation of the 50-month schedule whatsoever. Tr. Vol. 50 at 7942; Vol. 51 at 8113 (Curless cross). Nor did S&W or GSU apply Mr. Fawcett's 4/7ths factor in 1978-79. Tr. Vol. 53 at 12888-89 (Fawcett cross). Mr. Fawcett did not consider whether one could apply the 4/7ths factor to S&W engineering. Id. at 12894. The 50-month schedule itself was premised upon untested and unwarranted assumptions. The schedule assumed that GSU could financially support the accelerated schedule, an assumption which was not tested beforehand and which proved to be untrue. It also assumed that vendor deadlines could be moved forward to

meet the new schedule. OPC Ex. 151. That proposition was also unexamined, and GSU and S&W indeed had serious problems with vendors' ability to meet the 50-month schedule. Tr. Vol. 34 at 5488 (Schultz cross); Vol. 35 at 5562; Vol. 36 at 5795; CAUR Ex. 68. (Most of those problems eventually were resolved or worked around, including the most serious, delivery of the Power Generation Control Complex. Tr. Vol. 47 at 7477-78.) According to Mr. Clifford, the 50-month schedule when originally presented was premised on a scope of work identical to that set out in the May 1977 estimate—an obviously false assumption. In short, the evidence shows that the 50-month schedule was untested and hastily conceived in order to assure that S&W would retain its role as constructor of River Bend. As the River Bend Job History Report explains,

> In order to remain in contention during preaward negotiations, our management was obliged to make unprecedented schedule compression and cost control commitments. . . . In the limited time available for negotiation, S&W management had to present to GSU a credible plan for constructing River Bend in record time and within allowable cost parameters. This, in brief, involved accepting the May, 1977 Preliminary Estimate as valid and updating it for scope and escalation; then factoring in assumptions of the advantages to derive from the NCSA.

OPC Ex. 78 at 54, 57.

Even had there been a 30 percent probability of achieving the 50-month schedule, that aggressive target would not have been appropriate for comparing generation alternatives or for contingent financial planning. GSU's witness Mr. Fawcett agreed that the possibility of delay should have been considered. Tr. Vol. 53 at 12969-70. The likely schedule would have been more appropriate for determining the likely cost of the plant.

It is unclear what schedule GSU might reasonably have expected given the perceived capital requirements at the time. The Job History Report states,

> Our analyses indicate that given the requisite financial and manpower resources, and more timely impact resolution/avoidance, a cost-effective construction schedule of about 59 months could have been implemented.

OPC Ex. 86 at 8.

Bechtel's bid proposal, using rolling 4-10's, was for a first concrete to fuel load schedule of 61 months (as opposed to S&W's 62-month proposal without 4-10's). NUTECH had estimated that Bechtel had a 50 percent probability of meeting a 71-month schedule. OPC Ex. 451. Although GSU witness Fawcett contended that Bechtel did not contemplate the full use of rolling 4-10's, that does not appear to have been the case. OPC Ex. 247.

The 71-month estimate does not seem appropriate, considering that S&W actually completed the plant in 72 months with a much greater scope of work. The examiners therefore have chosen 60 months as a reasonable schedule for GSU to have contemplated at the time of the DCE. Such a schedule would still have been quite rapid and still would have meant completion in record time.

MHB based its cost of schedule delay on 1981 calculations by Mr. Curless. OKA calculated the actual costs of the later schedule extension. Those would appear to be too high, as one should be looking from a 1979 prospective. A more closely contemporary estimate, prepared in November of 1980, would have estimated those costs at approximately $110 million for six months, excluding purchased power, or roughly $183 million for a 60-month schedule, raising the DCE to approximately $1.912 billion. OPC Ex. 168; Tr. Vol. 110 at 17185 (Hadzi-Pavlovic cross). That figure may also be high from the 1979 perspective, as GSU's management was estimating in

August 1978 that delay was adding roughly $100 million per year to the cost of the plant.

(3) Known regulatory changes. The examiners found Dr. Mattson's testimony to be the most thorough and convincing on the subject of regulatory changes which should have been expected to increase River Bend's cost in 1979. They accept his finding that in 1979, based upon a comprehensive review of anticipated issues, a reasonable manager would have expected cost increases from the sources identified by Mr. Komanoff and MHB not to exceed $100 million. That figure encompassed $50 million attributable to unresolved safety issues and $50 million for TMI backfits as identified by the "Lessons Learned" report. Dr. Mattson considered the $100 million total to be a conservatively high figure, with a lower figure of approximately $50 million. The examiners therefore find that GSU should have expected $50-100 million in additional costs from those regulatory changes which, combined with the longer schedule, would raise River Bend's estimated cost to between $1.96 and $2.012 billion. In particular, the examiners find Mr. Komanoff's 25 percent TMI adjustment to be unreasonable from the perspective of 1979. It contrasts markedly even with the $40-80 million predicted by MHB. The examiners also find convincing Mr. Booker's analysis of the issues raised by PPC witness Beckhan, and agree that the increases in costs associated with those issues could not reasonably have been predicted in 1979.

The examiners do not mean to imply that GSU should have been confident that changes would not exceed $100 million. Stricter ASME standards, for example, would have been expected to increase costs some amount. As is discussed below, a contingency would have been appropriate for financial planning.

(4) Omissions from the DCE. OKA identified a number of alleged omissions from the DCE based upon its review of WPCNs and MECs. The examiners find that

Mr. Schultz generally effectively rebutted OKA's contention that those items were improperly excluded from the estimate. A number of those items, which were classified in the IEF as attributable to regulatory causes or escalation, or were attributed by OKA to schedule extension, are covered by the examiners' discussions of those issues. Others were covered by the allowance for indeterminates included in the Definitive Cost Estimate. Many of the MCCs and WCPNs were not available until late 1980 or even 1981, and some pertained to contracts not revised until well after September 1979.

The examiners do disagree with Mr. Schultz' evaluation of five of the MCC's and WPCNs identified by OKA. Although those changes occurred after the May 1 cut-off date, they took place before September. GSU should have known about them even though they were not in the formal DCE. Those changes—documented in WPCN 26, WPCN 200, WPCN 29, WPCN 118, and MCC 134—totaled approximately $18.370 million.

WPCN 26, in the amount of $1.621 million, added fire protection headers. WPCN 200, for $2.504 million, pertained to the fireproofing of steel. Both were required by Appendix A which contained NRC fire protection requirements. Apparently GSU had omitted them from its fire protection program in the belief that their omission represented legitimate exceptions to Appendix A. The examiners believe those costs should have been foreseen.

In June 1979, S&W submitted WPCN 29, which increased design costs of cooling towers. That increase was approximately $7.7 million. Although omission of that WCPN was within the instructions for preparing the DCE, GSU should have been aware of its existence.

WPCN 118 covered $221,000 of modifications to the radwaste building bridge crane. Radwaste building specifications were finalized in August 1979.

MCC 134 added $6.324 million in additional costs for startup testing activities to be performed by S&W. The scope of S&W's work was established in August 1979.

On the basis of those five items, the examiners would add $18.370 million to the DCE, for an expected cost of between $1.978 and 2.030 billion.

(5) Contingency. The examiners agree with GSU that it was prudent in not including a formal contingency in its 1979 DCE. An informal contingency would have been appropriate. The examiners are convinced that GSU was indeed aware of the possibility of cost overruns and was certain of its ability to finance the plant. Certainly GSU studied its possible exposures—Mr. Curless prepared monthly potential exposures reports beginning in February 1980. What level of informal contingency should have been examined by the company is open to debate. OKA suggested 10 percent of to-go costs, GSU witness Fawcett 15 percent of to-go costs. The examiners find 15 percent to be appropriate to cover not only unknown changes (such as those related to escalation or TMI), but also known but unquantifiable changes (such as the costs of stricter ASME piping criteria or ongoing vendor negotiations).

Sunken costs as of September 30, 1979, were approximately $412 million. Tr. Vol. 93 at 14458 (Houghton cross). Applying a contingency of 15 percent of to-go costs to the higher estimate set forth above, $2.030 billion, would yield a contingent estimate, for financial planning purposes, of approximately $2.273 billion.

(6) Escalation. The examiners find that the level of escalation set forth in the DCE was reasonable. It was based upon detailed analyses of job components and contracts and on predictions by the President's Council of Economic Advisors. MHB's application of the five-year Handy-Whitman average of 9.3 percent is simplistic and is skewed by an increase of 13.0 percent between 1974 and 1975, the first year of that five-year period. Removal of that year and reliance on a four-year average would yield an annual increase of 8.48 percent—almost identical to the ten-year average identified by Mr. Curless, which

was in line with the amounts actually included in the DCE.

(7) Econometric estimation. The examiners do not find GSU imprudent for having failed to consider the results of econometric estimation of nuclear plant costs. The DCE was thorough and specific to River Bend. GSU had no reason to doubt its general accuracy. As Dr. Pflaum testified, use of an engineering estimate, with an appropriate contingency, was appropriate at the time. Most importantly, one of the three practitioners of the econometric technique, Dr. Perl, had disavowed its use as a basis for estimating future plant costs.

c. *Mark III issues.* The examiners find Dr. Mattson, Mr. Sobon, and Mr. Booker to have been convincing in testifying that Mark III issues appeared close to resolution in 1979. To have included specific amounts for their resolution in the DCE would have been speculative. Any potential costs would have better been covered by a general financial planning contingency.

Certainly River Bend construction should not have been deferred until Mark III issues were resolved. Even MHB predicted in 1978 that the resolution of Mark III problems, including delays, would have cost between $10 and 30 million. That prediction hardly justifies deferring the plant or the $300 to $500 million disallowance which MHB now proposes.

d. *Nuclear/coal economic comparisons.* All the straightforward nuclear/coal busbar studies conducted at the level of the DCE suggested an economic cost advantage for nuclear power. Dr. Pflaum considered the nuclear advantage to be overwhelming at that level.

No party conducted busbar studies at precisely the levels suggested by the examiners for an appropriate DCE—$1.98 to $2.030 billion. Dr. Pflaum's comparison, however, at a $1.95 billion level, showed a cost advantage for nuclear generation. He found the break-even

point to be $2300/kW, or roughly $2.148 billion. Staff Ex. 58 at 69. Dr. Andersen showed the break-even point to be at a capital cost of $2135/kW, or approximately $2.007 billion. That is consistent with Mr. Lee's testimony, in which he stated that at a cost of close to $2 billion River Bend would still be the ultimately cheaper option. Tr. Vol. 57 at 9050. From that the examiners conclude that busbar studies conducted at capital cost levels of $1.98-2.03 billion for River Bend would either have been inconclusive or have shown a slight cost advantage for the nuclear option. Adding the 15 percent contingency would probably have shown a slight advantage for coal. The examiners note that Dr. Pflaum and Dr. Andersen used nuclear/coal capital cost ratios of approximately 2:1 in making those comparisons. Several contemporaneous studies suggested ratios more favorable to nuclear power.

As GSU's cross-examination of Dr. Pflaum showed, and as Dr. Pflaum agreed, busbar numbers can be made to "dance" by the manipulation of heat rates, capital structure, decommissioning costs, capital costs, capacity factors, projected O&M expenses, and other factors. By changing those assumptions, GSU was able to transform Dr. Pflaum's analysis into an advantage of as much as $940 million for nuclear power. Tr. Vol. 106 at 16681 et seq. (Pflaum cross); GSU Exs. 235-245. All parties agreed that busbar analyses alone cannot dictate generation planning decisions. Dr. Pflaum and Dr. Andersen both claimed that the uncertainties inherent in nuclear construction should have tipped the scales toward construction of coal-fired capacity instead. Dr. Andersen's gas displacement analysis also showed that a mere nuclear/coal comparison would not have captured the benefits occurring from the ability to construct additional coal-fired capacity and the consequent displacement of gas-fired capacity.

The examiners reject Dr. Pflaum's and Dr. Andersen's arguments. As has been mentioned above, the financial

uncertainties associated with nuclear power, although great, did not seem as overwhelming as the ultimate costs of those plants would now imply. The intervenors' highest estimate of approximately $2.6 billion would not have plunged the company into the financial abyss it now finds itself, nor would it necessarily have precluded the construction of additional coal- or lignite-fired capacity. Other uncertainties argued in favor of nuclear power, moreover—particularly uncertainty as to coal prices, the potential for pollution from coal-fired generation, and the possible financial effects of River Bend cancellation. The balancing of all those factors leads the examiners to the conclusion that proceeding with construction of River Bend was not imprudent, even given the higher DCE which the examiners believe would have been reasonable at the time.

The basic premise of Dr. Andersen's gas displacement analysis is simple—GSU could have built more coal-fired generation than nuclear generation for the same price. That additional generation would have displaced high-cost gas and helped GSU to meet its obligations under the Fuel Use Act. The examiners find, contrary to Mr. Smith's assertions, that Dr. Andersen used reasonable assumptions in making that comparison. The benefits of the gas displacement course, however, depended upon the stringence of financial constraints and on predictions as to the volatile price of gas. Therefore the level of benefit from gas displacement is itself subject to uncertainty. Dr. Andersen's selection of coal-fired generation as the optimal expansion path also does not take into account the uncertainties attributable to coal prices, pollution, and River Bend cancellation set forth above. Certainly, Dr. Andersen's gas displacement analysis identifies a reasonable alternative available to GSU. It does not show, however, that the path pursued by GSU was imprudent.

e. *Load forecasting uncertainty.* The examiners also reject the Cities' argument that volatile load growth

should have precluded construction of River Bend. It is undisputed that any reasonable load forecast would have predicted a need for capacity. The Fuel Use Act also demanded new construction. Yet the Cities argue that GSU should have built 300 MW coal units in order to protect its flexibility. It defies logic to assert that GSU should have planned its capacity expansion program on the unsubstantiated fear that its load projections would be drastically wrong. The examiners do not agree that GSU was imprudent in this regard.

f. *CEPCO buyback agreement.* Finally, the examiners find that the CEPCO buyback was a prudent transaction. The agreement enticed CEPCO to participate in the plant while at the same time giving GSU access to power which it thought it would need during the first years of River Bend's operation. GSU benefited from CEPCO's financial participation in the project. Because GSU was able at the same time to purchase a portion of CEPCO's Big Cajun 2-Unit 3 coal plant, it was also able to diversify its generation mix and reduce somewhat its asset concentration.

E. *Management of the Construction of the River Bend Project*

In the section below the examiners summarize and discuss various arguments related to the management of construction of River Bend. The examiners conclude that GSU has the burden of explaining why River Bend is one of the most expensive nuclear plants in the United States, particularly considering the cost savings which should have been associated with its rapid construction schedule. They find that the company failed to present a credible reconciliation of plant cost growth to legitimate causes. They find that costs were imprudently incurred in pursuit of the 50-month schedule and that the schedule resulted in some loss of construction productivity. They find waste and inefficiency in S&W's engineering effort and its implementation of the computer-

ized Engineering Management System. The costs from the reduction in productivity and from S&W inefficiency cannot be determined from the record, however. The examiners find no imprudence in GSU's handling of problems with the TDI backup diesel generators but conclude that GSU should nevertheless bear the cost of TDI's imprudence.

The examiners evaluate the statistical analyses of the reasonableness of River Bend costs presented by the parties. Those analyses attempted to adjust plant costs for various uncontrollable external factors to reach a reasonable expected construction cost. The examiners find the most reliable of those analyses to show River Bend's cost to be nine percent above its statistically predicted cost and find that GSU has failed to explain that difference. The examiners recommend that nine percent of River Bend's cost be excluded from GSU's rate base as imprudently incurred. Because the statistical analysis should capture the consequences of the imprudent or wasteful actions described above, the examiners recommend no further disallowances of plant costs.

1. GSU Direct Case

Dr. Marshall opened GSU's direct case by testifying as to the standards to be followed in evaluating the prudence of a utility's construction performance. Dr. Marshall stated that "prudence" is an attribute of decisions and actions only. It cannot be determined from results. Therefore regression analyses or other plant-cost comparisons are of only limited value. They "may be used to indicate some management action which could be suspected of being imprudent. However, the investigation must then focus on these suspected actions or decisions." GSU Ex. 35 (Marshall direct test.) at 20. Dr. Marshall testified that disallowances should not be based purely upon plant cost comparisons, but only on identifiable imprudent actions or decisions.

Dr. Marshall's analysis was offered in part as apology for the fact that the PLG Report, sponsored by Mr. Perla, did not contain a cost-per-kW comparison. Mr. Perla testified that cost-per-kW comparisons can be "misleading" and that they must be used in a "careful, appropriate manner:"

> Having looked at the cost per KW comparisons, we have made the inquiry into prudence of Gulf States' decisionmaking which is described in our Report. Having reached the conclusions which I have summarized here, and which are stated more fully in the Report, we did not feel it was necessary to include the cost comparison in our Report.

GSU Ex. 36 at 9.

Mr. Perla conceded that River Bend's cost, on an unmodified per-kW basis, is higher than that of a number of earlier units. Considering factors unique ot the project and the severe impacts of inflation and regulatory requirements during its construction, however, River Bend is not unduly expensive. Mr. Perla concluded,

> Q: Do you consider the cost per kw of River Bend to be an indication that the project has not been prudently and efficiently managed?
>
> A: No. Our study indicates to me that the ultimate cost of the plant is the product of decicisions, prudently made, which led inevitably to the ultimate cost of the plant.

On cross-examination Mr. Perla agreed that PLG had included cost-per-kW comparisons in its studies of the Palo Verde, San Onofre, and Seabrook nuclear plants. Tr. Vol. 21 at 3304. He also agreed that in its 1984 Palo Verde study PLG had observed, "Plant costs are best compared on a per kilowatt basis because this corrects the effects of cost differences due to plant size." Tr. Vol. 21 at 3343.

The PLG Report was the centerpiece of GSU's case on the prudence and efficiency of the construction of River Bend. It discussed River Bend's management structure, controls and effectiveness. It also pointed to numerous uncontrollable external factors (e.g. regulatory changes and inflation) which led to increases in River Bend's projected cost. The report stated that GSU had from the project's beginning been committed to a philosophy that encompassed the following elements:

1. Extensive direct involvement of top GSU management with the project engineer/constructor (S&W), and the Nuclear Steam Supply System (NSSS) contractor General Electric Company (GE).

2. Development of a project management team consisting of personnel who have extensive power plant engineering and construction management experience.

3. Early emphasis on project planning and the development of adequate cost and schedule controls.

4. Emphasis throughout the project on construction of a plant that incorporates the highest standards of quality.

5. Early definition of and reaction of all regulatory issues.

The report observed that GSU monitored S&W's engineering effort closely, "on a daily basis," although it left primary responsibility for those efforts to S&W. There was constant interaction between S&W's and GSU's engineers. In early 1980, GSU established a full-time presence at S&W's Cherry Hills Operations Center (CHOC). Also in 1980, a site engineering group was established to facilitate the interaction of engineering and construction.

The PLG report also described the evolution of GSU's River Bend organization. After 1977, after consultations with outside management consultants such as MAC, GSU moved to consolidate River Bend project design and construction under a single manager. Matrix concepts were also used to assemble a River Bend project team with representation from power plant construction, engineering, accounting, material services, and office services. In November, 1979, GSU established the River Bend Nuclear Group, a semi-autonomous organization charged with overseeing plant construction.

GSU also added experienced technical personnel, according to PLG. By the end of 1979, the number of GSU personnel available to support the project had doubled from 1977. Many of those people had nuclear experience.

The report stated that River Bend's QA organization met all the requirements of the NRC and that GSU had not compromised on quality or safety to attempt to meet its cost and scheduling goals.

The report described GSU's contracts with S&W and GE. The S&W contract contained provisions for a fixed fee to be paid over the life of the project, discretionary fees on the basis of performance, a construction schedule incentive program, and target man-hour levels which could vary the fixed fee payment amounts. When the schedule was amended from 50 to 68 months in 1981, the incentive plan was amended accordingly. The revised contract established 23 individual milestones. It stipulated that all 23 milestones, and full power operation, had to occur before January 1, 1986; otherwise S&W would progressively lose the incentive payments it had earned. S&W attained 18 of 23 project milestones and two of three end-of-year completion goals. Full power operation did not occur until June of 1986, however. S&W earned 46 percent of the construction completion award fund established by the revised contract.

The PLG Report defined the basic elements of project control as:

> an organization dedicated to cost and schedule control, a project plan including schedules and budgets, tools and procedures for recording and monitoring performance against the plan, and a reporting system that communicates project status and deviations from the plan to the appropriate personnel for their corrective action.

PLG believed that GSU and S&W implemented such a system. That system allowed GSU to maintain efffective control of the project, which nevertheless was affected by uncontrollable external forces. In discussing GSU's controls, the report pointed out that GSU received monthly progress and status reports that provided detailed breakdowns of the dollars and man-hours expended by S&W engineering and design. GSU's ability to monitor the project was enhanced by the use of the computerized S&W Integrated Management System (SWIMS). GSU periodically audited the Engineering Management System (EMS) and Construction Management System (CMS) data bases which comprised SWIMS.

PLG emphasized the daily interaction between GSU and S&W personnel, along with the 1980 placement of GSU engineers at CHOC and at GE's facility in San Jose, California. GSU and S&W also held periodic engineering status meetings. Each month GSU developed a planning and cost analysis summary report based upon data from the project files and information from GSU and S&W personnel. Project change procedures required WPCNs and MCCs to be issued by S&W and thoroughly reviewed by GSU personnel. S&W's review of vendors involved reviews of their qualifications; monitoring of quality, production schedules, and delivery duties; and regular shop inspections.

The report discussed management's responses to changing circumstances. It discussed in particular GSU's par-

ticipation in a number of owners' groups such as the BWR-6 Owners' Group, the Mark III Owners' Group, and the Transamerica Delaval, Inc. (TDI) Owners' Group. The last of these, composed of 12 utilities, was formed in 1983 after the failure of a TDI diesel generator at Long Island Lighting Company's Shoreham plant.

PLG examined River Bend's testing program. It concluded that those efforts were well organized and efficiently handled.

PLG examined "two key project measures"—construction schedule performance and labor productivity—to reach the conclusion that the management of River Bend was timely and efficient. PLG found that River Bend had the shortest construction duration of any of 25 nuclear plants. Its schedule was 49 months shorter than the mean of those plants. PLG's comparison of labor productivity data showed River Bend productivity to have been better than average for eight of eleven major bulk commodities, the exceptions being structural steel, small diameter pipe, and large pipe supports.

PLG examined GSU's management of and the effects of NRC requirements in the following areas: Mark III loads, fire protection, equipment qualification, TMI, and quality assurance and control. It also emphasized that GSU had a good compliance record, no major licensing delays, and above average inspection rating.

PLG stated that although resolution of the Mark III loads problem had a significant impact on River Bend, the plant did profit by the construction halt. During the hiatus period, much analysis was performed, of which GSU was able to take advantage when it resumed construction. The ultimate solution, suggested by GE in 1979 and implemented by GSU in 1981, was to partially fill the annulus between the containment and shield build-

ings with concrete. GSU hired an independent consultant to review that recommendation before proceeding with it.

The 1975 fire at TVA's Brown's Ferry plant impelled new NRC fire protection regulations. Those were primarily set forth in 1976 in Appendix A to Branch Technical Position 9.5-1. Utilities could suggest alternatives to Appendix A; issues which remained unresolved came to be referred to as "open items." The NRC attempted to resolve those items in Appendix R to 10 C.F.R. 50, which was first issued for public comment in May 1980 and became effective in February 1981. The rule originally applied to plants, unlike River Bend, with operating licenses issued before January 1, 1979. The NRC's staff in October 1981 asked GSU to review its fire protection program against Appendix R, however. The most significant feature of Appendix R was the following requirement:

> (a) redundant trains of safety equipment must be separated by 3-hour fire barriers, 20 feet of open space, or 1-hour barriers in combination with automatic fire detectors and sprinklers; or (b) an independent alternative shutdown path must be provided.

The report stated that the NRC's interpretation of that requirement gradually became more stringent. Although GSU was able to reach some compromises with the NRC, and although River Bend again profited by its later construction date, the NRC's evolving fire protection requirements added significantly to the plant's cost.

According to PLG, the basic requirements for equipment qualification were significantly expanded upon and modified in December 1979 when NUREG-0588 was issued for comment. The proposal became a requirement in May 1980. The interpretation of those requirements continued to change throughout the 1980s. Those changes

required more equipment testing, as opposed to analysis, and considerably more documentation.

PLG stated that the most significant "TMI requirements" were set forth in the "Lessons Learned" report of July 1979 (NUREG-0578), the TMI Action Plan of April 1980 (NUREG-0660), and the Clarification of TMI Action Plan Requirements of November 1980 (NUREG-0737). The NRC continued to reinterpret those requirements through the 1980s. An October 1979 letter outlined the extent to which the "Lessons Learned" recommendations applied to River Bend and other BWRs. PLG found that specific NRC requirements and increased NRC scrutiny added significantly to engineering and construction costs. Again, River Bend benefited from its relatively late construction, which minimized the impacts of TMI-related backfits. Mr. Perla observed on cross-examination, however, that

> the TMI impact itself had far greater repercussions on plants which had yet to do major portions of their construction in 1982, '83, '84 or when the NRC did, in fact, place much more rigid inspection requirements on the plant construction and energy programs.

Tr. Vol. 21 at 3342.

Quality Assurance requirements also increased after 1979, PLG stated. After TMI, the NRC initiated a number of additional on-site inspection programs, including,

- Systematic assessments of licensee performance (SALP) to assess licensee QA/QC performance (initiated in 1979).
- Construction appraisal teams (CAT) to provide in-depth inspections and audits of construction projects (initiated in 1980).

* Independent design verification programs to verify plant design (initiated in 1981).

* Integrated design inspections (IDI) to verify implementation of licensee QA/QC programs during the design process (initiated in 1982).

NRC inspections of River Bend included 123 routine inspections, four SALP assessments, one CAT inspection and one IDI.

PLG also assessed GSU's response to the TDI generator problems. After the generator failure at Shoreham, GSU instructed S&W to place an option to purchase a Colt Industries diesel generator. It also proposed a method, ultimately approved by the NRC, for redistributing some load away from the TDI diesels.

According to PLG, River Bend was affected not only by regulatory changes, but by higher-than-expected inflation and interest rates. PLG analyzed the reasons for the cost growth between the DCE and River Bend's actual costs, and attributed those increases to the following causes: regulatory requirements (46 percent); inflation (9 percent); AFUDC (20 percent); and design development (25 percent). It based the regulatory percentage on the amounts coded to regulatory change in GSU's Incremental Estimate File (IEF). It observed that that percentage was low compared with studies of that subject for other nuclear projects.

Messrs. Draper, Helmick, Glazar, Curless, and Schultz all discussed GSU's management and control of S&W and the project. Dr. Draper described the evolution of GSU's management structure for River Bend, including establishment of the position of Project Manager in 1977, hiring of experienced nuclear personnel, and creation of the River Bend Nuclear Group in 1979. He emphasized that the RBNG, though subject to ultimate corporate

control, had broad authority to negotiate contracts, procure materials, and implement the project. He indicated that the Senior Vice-President in charge of the RBNG made presentations at the regular Board of Directors meetings and reported regularly to management. He testified that GSU had hired outside consultants to regularly audit quality assurance and management at River Bend. Dr. Draper emphasized that GSU placed a high priority on quality and safety and had consistently received positive evaluations from the NRC. In summary, he stated,

> I am fully satisfied that Gulf States has applied strong, effective management policies and techniques to the River Bend project at the senior corporate level, consistent with sound modern theories of management. However, I cannot represent that I am fully satisfied with the ultimate result of the River Bend project, since its costs are higher than I would like to have seen. I am convinced that these cost levels are not the product of inadequate management policies and techniques. Rather, they reflect the unavoidable effects of unpredictable changes in various economic, technical and regulatory factors during the project's construction period.

Mr. Randall Helmick of GSU also described GSU's monitoring of S&W's construction performance. Mr. Helmick testified that the principal elements of that program were:

1) the computer-based Construction Management System (CMS);

2) work sampling programs to evaluate S&W's utilization of craft labor;

3) on-site reviews of design constructability; and

4) direct involvement in day-to-day construction decisions and activity.

CMS was used for both forecasting and monitoring. Material quantities from construction drawings and labor rates from historical industry averages were entered into the computer, which could predict scheduling and cost projections and identify durations from those projections.

Mr. Glazar described GSU's control over S&W engineering. He recited the nuclear training and experience of GSU's personnel and their interaction with and monitoring of S&W. Mr. Glazar testified that there was constant interaction between S&W Engineering and GSU's Engineering Group. GSU's engineers were fully involved in the engineering and design process. He also described other control and monitoring methods including a comprehensive system of meetings, reports, and task forces, as well as the computerized Engineering Management System. He described EMS as "a computerized cost and schedule system based upon: (1) a defined scope of work; (2) a network-based logic for performing the work; (3) the assignment of responsibilities for the work; and (4) an estimate of the resources (man-hours) needed to perform the work." Before EMS became available in October of 1979, S&W's monthly bills provided detailed breakdowns of the engineering expenditures in each engineering division. Mr. Glazar also testified that GSU required that all significant engineering changes be approved by GSU Project Engineering.

Mr. Glazar also discussed certain unique design features which increased the cost of River Bend. Those included the use of galvanized steel; the addition of truck aisles for maintenance; the location of the makeup water pumphouse close to the Mississippi River; the size of the makeup water pumphouse (built for two units); the size of the radwaste structure; the location of the switchyard; the design of the diesel generator building (with fuel oil storage tanks in its basement rather than outside); and the size of the makeup water clarifiers. Mr. Glazar did not attempt to quantify those costs.

Mr. Curless discussed the RBNG generally as well as its supervision of S&W. He indicated that RBNG constantly monitored the cost and scheduling information provided by S&W and audited the EMS in the fall of 1980 with follow-up audits in 1982 and 1984. He agreed that the initial audit found some problems in EMS which he considered typical of any new "state-of-the-art" system. S&W took action to correct those problems. Although the second audit found that some problems remained, it found no fundamental flaws with EMS.

Mr. Curless also discussed the Incremental Estimate File, which tracked changes to the DCE. Under the IEF changes could be assigned to one of nine "basic generic" reason-for-change categories: Scope, Regulatory, Design Development, Vendor, Escalation, Rework, Transfers, Schedule Extension and Allowance for Indeterminates. Any changes to any safety-related structures were placed into the "Regulatory" category. Tr. Vol. 51 at 8074-75 (Curless cross). Mr. Curless also testified that GSU maintained a good working relationship with S&W and its vendors throughout the project.

Mr. Schultz of S&W expressed the opinion that engineering costs for River Bend were not excessive or unreasonably high. He emphasized S&W's role in providing startup testing services, QA/QC audits and services, job site engineering, and some procurement. Mr. Schultz also testified that all costs incurred in pursuing the 50-month schedule would eventually have been incurred anyway.

Dr. Mattson and Mr. Booker discussed in more detail the effects of changing regulatory requirements on River Bend. Both observed that the GE load definitions for the Mark III containment were not finalized until early in 1980, when GE applied to the NRC for final design approval. The NRC staff completed its generic review of Mark III hydrodynamic loads in February 1984. Mr. Booker contended that the new loads problems were the consequence of changing NRC interpretations of its regu-

lations. He stated that GSU could not have been sure until the NRC's 1982 preliminary evaluation or even its final review in 1984 that changes would be necessary. Nevertheless, to avoid costly delays GSU proceeded with the annulus concrete fill in 1981 to satisfy potential NRC concerns.

Dr. Mattson and Mr. Booker agreed that evolving NRC fire protection requirements added significantly to the cost of River Bend. They emphasized in particular the addition of alternative remote shutdown facilities and modifications required to the remote shutdown panel.

River Bend was the first BWR required to meet the requirements of IEEE 323-1974. That standard entailed more stringent requirements for the qualification of electrical equipment in harsh environments than did its predecessor. According to Dr. Mattson and Mr. Booker, stricter NRC interpretations issued in December 1979 and affirmed in May 1980, and others issued even later, added to the cost of River Bend. Those interpretations required much more equipment testing and documentation.

Dr. Mattson indicated that TMI required both personnel and hardware changes. Of greatest significance, however, was increased scrutiny in the 1980s, which flowed in part from the accident and in part from the later failures of plants under construction such as Zimmer. Mr. Booker also briefly discussed TMI requirements issued in the 1980s.

Dr. Mattson stated that changed QA requirements were the most significant cause of growth after 1979. Both he and Mr. Booker emphasized additional inspections, documentation, and design changes and verifications resulting from those stricter requirements. Dr. Mattson particularly emphasized the imacts of regulatory scrutiny and the NRC "get-tough" policy arising not only from TMI but from Zimmer and other plant-

under-construction failures. He observed that from 1979 to 1982 new requirements "flowed out of the NRC staff in a growing number of generic letters, bulletins, and standard review plans." In his view the backfit process grew "out of control" until 1982, when the NRC formed its Committee to Review Generic Requirements to bring more discipline and centralized direction to the process.

2. PPC Case

The PPC case, like that of GSU and other parties, has already been summarized to a great extent in the "Restart" section of this report. A number of additional points requires mention, however.

Mr. Komanoff compared River Bend's actual cost to those of other nuclear plants. He testified that the "definitive" measure of comparative power plant costs is the inflation-adjusted direct cost per kilowatt. On that basis, River Bend was "remarkably expensive." Mr. Komanoff stated that River Bend's cost exceeds the average cost of 29 other current nuclear projects by 47 percent, that it is the most expensive nuclear project ever built in the Southern United States, and that is 77 percent more expensive than the average of the other Southern plants. His sample consisted of projects licensed for completion during 1972-78 and completed or scheduled for completion during 1983-90. He downplayed the importance of River Bend's admittedly rapid construction schedule, since that rapid schedule did not translate into low construction costs.

Using multiple regression analysis, Mr. Komanoff adjusted plant costs for a number of variables. He described multiple regression analysis thus:

> Multiple regression analysis is the standard method for correlating data to overlapping causal factors. It provides estimates of the magnitude and statistical significance of correlations between a "dependent" variable (cost, in this case) and independent vari-

ables such as number of units per site, local wage rates, etc. The magnitude of a correlation, as shown by an independent variable's "regression coefficient," indicates the amount by which the dependent variable changes when the independent variable changes; the statistical significance of the coefficient denotes whether the strength of the correlation goes beyond mere random chance. The purpose, and result, of multiple regression is to isolate and measure factors that explain why some projects cost more than others.

Mr. Komanoff compiled a list of possible independent variables (e.g. multiple units per project) that might be correlated with the dependent variable (cost). A statistical computer program processed plant data and distilled them into equations which assigned variations in cost to variations in each independent variable. The output of that process was a listing of the magnitude and statistical significance of each independent variable's correlation with cost. He discarded those variables whose statistical significance fell below a selected threshold. He identified the following factors as statistically significant after satisfying himself that they made intuitive sense as contributors to plant costs:

1. Twin-Reactor Project (corresponds to 35% lower cost)
2. Northeast U.S. Location (corresponds to 29% higher cost)
3. Higher-Priced Labor Market (corresponds to 6-7% higher cost for a 10% higher wage rate)
4. Regulatory Work Stoppage (corresponds to 85% higher cost)
5. Inclusion of a Cooling Tower (corresponds to 30% higher cost)

In his model those factors together explained 78 percent of all variance among the costs of the 29 projects.

The analysis suggested that River Bend's cost per kW was increased by its being a single-unit project and requiring a cooling tower. Its costs were reduced by its Southern location, the relatively lower wage scale in the Baton Rouge area, and the absence of a regulatory-mandated work stoppage. Mr. Komanoff calculated River Bend's expected cost at $2559/kW, slightly above average. Its actual cost, however, in 1984 constant dollars, was $3681/kW, 44 percent above that expected cost.

Mr. Komanoff explained why those particular factors would contribute to plant cost. Second-unit reactors are generally cheaper than first units due to economies of scale and greater project momentum and efficiency. Plants in the Northeast can suffer from population density and more stringent environmental regulations. The wage factor is obvious. He calculated it based on the average construction wage in the vicinity, which varied from a low of $13.40/hour in the Carolinas to over $25.00/hour for Shoreham in New York and SONGS in Southern California. The weighted rate for River Bend, based upon wages in Baton Rouge and New Orleans, was $16.18, which was 15 percent below the mean.

Mr. Komanoff included three projects in his regulatory work stoppage group—South Texas, Clinton, and Comanche Peak. The first two suffered protracted shutdowns mandated by the NRC; the third, in Mr. Komanoff's opinion, had suffered a *de facto* stopwork order by virtue of the massive reinspection and rework it has undergone. Mr. Komanoff considered that variable reasonable because prudent plant costs should not be calculated as if shutdowns were to be expected. In other words, it compensated for the cost-inflating impact of "egregious mismanagement."

Mr. Komanoff explained that cooling towers had historically been shown to be correlated with increased plant costs. He could not conclusively state that the perceived

effect of 30 percent was entirely attributable to the towers themselves. He did point out that inclusion of the cooling tower favored River Bend. He ran another analysis eliminating that variable, under which River Bend exceeded its predicted cost by 62 percent.

Mr. Komanoff did not distinguish between plants with earlier and later construction permit dates within the 1972-78 period. He pointed out that his model adjusted for the effects of inflation and testified that a later construction permit date within his group of 29 plants did not correlate with higher costs. In his opinion, TMI affected all plants under construction significantly, but more or less equally. Plants licensed earlier may have been subject to fewer regulations, but those regulations required more costly rework.

Mr. Komanoff also rebutted statistical analysis filed by Dr. Perl for GSU.[7] He anticipated, correctly, that Dr. Perl would conclude that River Bend's actual cost differed little from its expected cost. The examiners will summarize Mr. Komanoff's observations in their discussion of Dr. Perl's statistical analysis.

Mr. Komanoff also attacked PLG's cost comparison analysis, which he received in response to discovery in Docket No. 6525. PLG did not present that cost comparison in this case. The examiners will discuss Mr. Komanoff's observations in their summaries of Dr. Perl's and Dr. Pflaum's testimonies to the extent they are relevant.

Mr. Komanoff also discussed the unique design features identified by Mr. Glazar. He pointed out that Mr. Glazar did not quantify the cost impacts of those features and stated that some other plants possess those same "unique"

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[7] Dr. Perl was a GSU rebuttal witness in this docket and therefore filed his testimony after Mr. Komanoff. He had filed in Docket No. 6525, however, and was expected to file in this case. Mr. Komanoff and Dr. Perl have been adversaries in several nuclear prudence proceedings.

features. He further contended that Mr. Glazar had failed to identify features favoring River Bend. To the extent that some of the features had been built to serve River Bend 2, he argued for their exclusion from River Bend costs.

In response to Dr. Marshall Mr. Komanoff acknowledged that statistical analysis is not perfect. Dr. Marshall's position, however, that such analyses should not be used to determine prudence, would in Mr. Komanoff's opinion deny the Commission a powerful tool with which to analyze the reasonableness of construction costs.

How regression analyses should be used in a prudence proceeding was a crucial argument in the case. As mentioned, GSU witnesses contended that such analyses should only be used to rebut a presumption of prudent utility behavior. If the analysis showed the cost of the plant in question to be relatively high, the inquiry should then turn to specific contested actions and decisions. If no specific imprudence was found, however, a disallowance should not be based on the results of regression analyses alone.

Even if a disallowance were to be based upon regression analysis, it should not be based on a point estimate, according to GSU. One can reach a certain point estimate, but that estimate has confidence bounds on either side of that predicted value. GSU contended that if the plant's actual costs fell within that confidence range, it would be inappropriate to disallow a portion of those actual costs. Mr. Komanoff disagreed. That dispute was the subject of an interesting colloquy between GSU attorney George Avery and Mr. Komanoff. Tr. Vol. 75 at 11429-43. Mr. Avery presented the hypothesis that the Commission had examined every disputed action and decision of the utility and had found each to be prudent. Although Mr. Komanoff questioned the Commission's ability to review every decision and action, the discussion proceeded under that hypothesis:

Q: And what I wanted to ask you is, isn't it true that in those circumstances, under that hypothesis, you would still recommend that any cost in excess of the cost predicted by your regression analysis be disallowed?

A: That's almost true. I would grant some modest error band around the statistical prediction, so that if River Bend came in a few percent higher than its statistically predicted cost, and if I were a Commissioner I doubt that just on the basis of that evidence that I would vote to disallow that two or three percent.

I don't know exactly where my cut off is. There would be some feel that would enter into my judgment. I think when we get into double digits that I would—my starting point would be that somebody ought to do a damn good job of persuading me as to why I shouldn't take every single percent in that double digit difference between actual cost and the norm. Somebody better do a real good job why I shouldn't take that out of the Company.

Q: All right. But—

A: Regardless—

Q: —I want to be clear that in making that statement you still are bearing in mind the hypothesis that I put to you before, that the Commission has examined every respect in which it's been suggested that there was imprudence and has concluded that there was no imprudence.

A: Right.

Q: You have that in mind in stating what you just stated?

A: I do.

Q: You're saying that it's still incumbent upon the Company to make an explanation?

A: Yes.

Q: Isn't it also true that you reject—and you've done this in other cases—you reject the possibility that the Company apply the confidence level aspect of statistical analysis to the study that you present?

• • • •

A: Yes. I'm rejecting at this final stage, although the underlying analysis that leads to my prediction or my calculation of what the plant should have cost uses these confidence intervals constantly. But yes, in this final test, I don't think it's appropriate to require the ratepayers to shoulder the burden of proof that there is a 95 percent chance or even a 90 percent chance that this difference between the actual and expected cost is statistically significant.

Q: I think for the purposes of the record we ought to maybe spend a minute or two on what we're talking about.

A: Good. I was thinking that, too.

Q: What we mean here is that in statistical analysis, you can reach a predicted point value, but then you apply certain statistical methods and I hope we don't have to get into them, but you can apply certain statistical methods that will tell you—give you confidence bounds on either side of that predicted value.

A: Yes.

• • • •

Q: Now, let's take the 95 percent confidence level, though.

A: Uh-huh.

Q: At that level, if you're within that band established by the 95 percent confidence level, then it can be said under statistical theory that the variation between the predicted and the actual is not statistically significant. Isn't that correct?

A: No. All that can be said is that the variation is not statistically—it's not significant to the 95 percent confidence level.

• • • •

Q: And the 95 percent confidence level as you said is one that is regularly used in statistical analysis as an appropriate level of confidence.

But you reject using it at this final state here?

A: It's frequently used to determine the validity of the individual variables. It's also used in experiments of a more scientific nature, or where there are extremely large data sets, or where—let me end the sentence and say, it's not to my knowledge routinely used in situations where two or more claimants are being forced to wrestle over very large sums of money. And in which, as far as I can see, there is no a priori basis for giving one side the advantage over the other.

• • • •

Q: All right. So therefore, drawing together the two topics we've been talking about in the last few minutes, isn't it a correct statement to say the following: You present a study which compares actual cost and predicted cost. You say everything above the actual should be disallowed in the absence of an explanation.

Are you with me? Am I correct so far?

A: Except for this little modest—

Q: Right, that little band.

A: —single digit. Somewhere in the single digit little band.

Q: Right. But, you also say you're not permitted to explain it in terms of the prudence and reasonableness of your behavior which is challenged. Right? You rule that out because you said you would require an explanation even if everything is found to be reasonable and prudent. That's correct, isn't it?

A: Right. . . . [A]s a Commissioner, I wouldn't be interested or I wouldn't limit my interest to the Company presenting me with evidence of how it followed all the right procedures and did all these things that management analysis supposedly tells us is the right way to manage a big project. I'm interested in the results. I've got to be interested in results.

• • • •

Q: Nor would you permit the utility to come in and say in justification of the difference between the predicted and the actual value, it's within the 95 percent confidence level?

A: Right. I absolutely would not.

Q: And so the burden you would place on a utility when you have a difference between the predicted and the actual value that exceeds the small band you would permit, is to—you give me an explanation but it can't be the reasonableness and the prudence of your actions, and it can't be grounded in that aspect of statistical theory, but you find an explanation and give it to me. That's what you're saying, isn't it?

A: Right. . . .

Tr. Vol. 75 at 11429-41.

MHB discussed GSU's handling of the Mark III containment and the TDI diesel issues.

The Mark III issues have been discussed in some detail in the "Restart" section of this report. MHB testified that the unavailability of detailed cost records made it impossible to quantify the cost of the disruption, rework, and reanalysis caused by Mark III decisions. They estimated that "imprudent decisions and analytical errors cost GSU on the order of several hundred million dollars." Without cost details, however, they substituted a delay cost of two to six months, or $67-201 million "as a direct and disruptive cost proxy." They based their estimated delay cost on an S&W estimate presented to GSU in June 1981 and on delays reported in piping installations.

MHB testified that GSU had imprudently poured the basemat for River Bend without designing it for "the most likely solution" to the loads problems--the concrete annulus fill. That solution had been identified in 1979. GE was recommending concrete fill for certain TVA plants and recommended it for the Perry plant in September 1979. GSU finally decided to implement the concrete fill in June 1981. Meanwhile GSU had continual problems due to an error found in the calculation of the amplified response spectra (ARS), a key element used to quantify the effects of various loads on systems and components within the reactor building. If not in 1979, GSU should have authorized the annulus fill by March 1981, after the errors in the ARS model had been corrected. MHB also faulted GSU for waiting until 1979 to authorize GE to proceed with the New Loads Adequacy Evaluation. GE had recommended the assessment in May 1977.

MHB contended that delay in implementing the annulus fill caused "increased reactor building and piping installation schedule durations, the backfitting of piping and hangers, equipment requalification, and substantially

increased engineering time, reanalysis and redesign." By going ahead and pouring the basemat, GSU failed to protect the ease with which the annulus fill solution could later be implemented.

MHB estimated the overall costs of Mark III after February 1979 at between $300 and 500 million. To derive that figure, MHB considered the costs attributable to Mark III problems at Perry and Clinton. MHB had identified the costs at Perry as "massive," causing several years of delay and at least a billion dollars in expense. PLG had concluded that Mark III issues cost at least $415.5 million, plus AFUDC, at Perry. Touche-Ross had suggested $673 million. MHB had found Mark III issues to have cost several hundred million dollars at Clinton. Touche-Ross had identified Mark III as the cause of 27 months of delay at Clinton, or approximately $429 million. MHB therefore concluded that the costs at River Bend were similar—on the order of $300-500 million.

In cross-examination, however, Mr. Bridenbaugh agreed that River Bend had not experienced delays comparable to those at Perry and Clinton.

Q: Well, do you agree that the delay costs at those plants [Perry and Clinton] were a large part of the Mark III costs at those plants?

A: Yes.

Q: And yet you do recognize that there were no such delays at River Bend, don't you?

A: I certainly wouldn't agree that there were no delays at River Bend; but they were not of the magnitude, as I said earlier, that occurred at Perry and Clinton.

Q: And this was because the construction schedule at River Bend was later in time?

A: At least partially due to that, yes.

Tr. Vol. 64 at 9945 *et seq.*

Mr. Bridenbaugh went on to explain that River Bend took its delay at the "front end" of the project—in other words, during the 1977-78 period when the project was on hold anyway. Id. at 9948-49. He distinguished that situation from Perry and Clinton:

> Q: But in terms of construction delay, do you distinguish the delays at Clinton and Perry from the delays at River Bend or are they similar?
>
> A: I guess I would distinguish them as different to the extent that construction had not really started at River Bend and so there was—it's kind of an apples or oranges question, because construction wasn't underway; there wasn't a construction delay. The project hadn't been staffed up and so there weren't the ongoing standby costs that occurred at the other projects—that occurred at River Bend as did occur at the other projects.

Id. at 9949-50.

When asked what documents supported MHB's estimated $300-500 million cost for River Bend, Mr. Bridenbaugh nevertheless again referred to the costs attributed to Mark III problems at Perry and Clinton. He also cited GSU's admission that Mark III had a significant impact on the project.

In 1983, the NRC lost confidence in the diesel generators manufactured by TDI. Those generators were meant to provide emergency power to safety equipment. Although the key event was the failure of a generator crankshaft at Shoreham in that year, MHB identified a long-standing pattern of deficiencies in TDI manufacture and quality control. MHB concluded that the NRC would not have lost confidence if GSU and S&W had prudently controlled their quality assurance activities.

Quoting 10 C.F.R. 50, Appendix B, MHB also pointed out that GSU bore ultimate responsibility for quality assurance.

> The applicant shall be responsible for the establishment and execution of the quality assurance program. The applicant may delegate to others, such as contractors, agents, or consultants, the work of establishing and executing the quality assurance program, or any part thereof, but shall retain responsibility therefor.

MHB cited a series of S&W memoranda beginning in 1975 expressing reservations about quality assurance and control at TDI. Audits were conducted in 1975, 1976, 1978-79, and 1980. All found flaws with TDI. The September 1980 audit recommended issuance of a stopwork directive, which was lifted in October. MHB concluded that S&W and GSU had addressed the symptoms at TDI, but had failed to cure underlying problems.

After the failure at Shoreham, the TDI Owners' Group, of which GSU was a member, took actions designed to restore confidence in the TDI diesels. Specific GSU actions included reanalyses and redistribution of TDI loads, hardware modifications, and purchase of an option for Colt Industries diesels.

Relying on a GSU document, MHB identified $10.5 million in otherwise avoidable costs attributable to TDI problems. MHB also estimated disruption equivalent to 30 days, or another approximately $54 million cost. MHB recomended a $64 million disallowance for imprudently incurred TDI costs.

OKA evaluated the 50-month schedule, the reasons for River Bend cost growth, and GSU's organization and control over S&W.

OKA determined that at least $45,777,000 plus AFUDC, for a total of $74,680,000, had been spent by GSU in pursuit of the 50-month schedule. It based that cost figure on the River Bend CASAR:

Description of Change	Total
Revise headquarters man-hours to support 50-month construction schedule	$30,568,000
Transfer of work to Force Account due to fabricators inability to meet accelerated schedule	5,336,000
Design modification required to meet accelerated schedule	(1,632,000)
Additional construction facilities or resources required to meet accelerated schedule	11,505,000
Total	$45,777,000

Unfortunately the record does not explain why "design modification" reduced plant costs.

OKA also analyzed the reasons for change identified in the incremental Estimate File and endorsed by the PLG Report. OKA evaluated changes to the DCE representing 95 percent of the total cost growth of the project. OKA concurred with the IEF's assignment of causes for approximately $218.5 million. It disagreed with the code assignment for approximately $137 million, most of which had been assigned to "regulatory," but did not take exception to the validity of those changes. As has been mentioned in the "Restart" section of this report, it attributed approximately $347 million to omissions from the DCE. It also contended that $445.9 million in cost changes were supported by inadequate documentation. According to OKA,

> While the reasons offered are at least conceptually acceptable, the support documentation provides very little to persuade the reviewer of their reasonableness and virtually nothing in the way of quantification of costs.

OKA concluded that the IEF supported the attribution of $378 million, at most, to regulatory changes compared with approximately $657 million identified by PLG.

OKA did not recommend any disallowance, however, aside from the purported effect of omissions from the DCE on the restart decision. In other words, OKA did not contend that any of the expenditures which it reviewed, other than the $75 million attributed to the 50-month schedule, should be set aside as imprudent.

OKA also analyzed each of the "unique design features" identified by Mr. Glazar. Mr. Winn testified that all of those features combined would not have had a significant impact on the project's cost.

OKA's analysis of engineering management has been discussed in the Restart section of the report. The examiners have rejected the contention that inadequate control by GSU led to an inaccurate DCE. That does not preclude the argument that engineering was inefficient during the project and that that inefficiency led to cost increases. Mr. Allen's August 1, 1980 letter to Mr. Crawford suggested as much:

> As you know, we have exerted a major effort to marshall our engineering resources to this project after your reactivation of the work 17 months ago. The magnitude of this task should be evident when one considers that the staff of approximately 200 engineers and designers in January, 1979, was tripled within six months and quadrupled by the end of the year. A significant portion of the Cherry Hill effort is being accomplished on a heavy overtime schedule varying from 8 to 18 hours per week. Under such workload, some efficiency loss is unavoidable (the EMS performance index for the month of May shows 86 percent effectiveness). We fully expect an improvement in efficiency as overtime is phased out and the project staff is reduced in 1981.

OKA also pointed to problems, identified in the 1980 audit, with the EMS system. The audit expressed doubt

as to the accuracy of EMS output and the overall headquarters percentage-complete figures. The audit suggested that problems in the system were aggravated by the 50-month construction schedule,

> which requires maximum overlap between the beginning of construction and the end of engineering. Drawings must be released in partially completed form to support construction and final calculation verifications and revisions to formally document changes lag behind.

PPC Ex. 10 at 5-21.

Mr. Curless observed, in an interview with PLG, that GSU had attempted to have its engineers track each work package in EMS. When that proved too cumbersome, GSU decided in April 1980 to place engineers at CHOC to track engineering design. Id. at 5-32. Also according to PLG's notes of its interview with Mr. Curless,

> Individual GSU discipline engineers @ CHOC keep up in monitoring of their 30-40 packages. Busy reviewing work packages, etc. Curless sent two C&S engineers who used drawings and specs and materials lists to measure progress and didn't use EMS. Use 'top ten' critical items to focus on. Due dates came from CPM analysis of construction. Never had integrated networks. Start up dates drove construction drove engineering date.

Like OKA, Mr. Beckham of TAC concentrated on what GSU and S&W should have known at the time the DCE was prepared. His testimony also had implications for the issue of costs incurred during construction, however. Although he believed many fire protection requirements could have been anticipated, he also agreed that the requirement for redundant, dedicated remote shutdown could not have been foreseen and that it added to the cost of the plant.

Mr. Beckham believed that some changes in equipment qualification standards should have been anticipated, but not their full impact. He believed that a proper QA program would have cost the same regardless of increased NRC inspections and emphasis after TMI. He agreed that TMI-related changes did have affect on plant costs. Mr. Beckham concluded that Dr. Mattson's and Mr. Booker's attribution of significant increases to regulatory scrutiny was unsubstantiated, however.

Mr. Beckham also discussed GSU's pre-operational and startup testing programs. Although there were delays, he considered the conduct of the pre-operational testing program to have been reasonable. He found that he could not judge whether the length of the start-up program was reasonable. Although GSU stated that the original 9-month schedule had been met, Mr. Beckham could not determine what the "original" schedule was. He therefore concluded that GSU had not proven the reasonableness of its conduct of the start-up testing.

3. GSU Rebuttal Case

Due to procedural peculiarities, staff consultants Mr. Hadzi-Pavlovic and Dr. Pflaum filed their testimonies after the company filed its rebuttal case. For that reason the examiners will next review the company's rebuttal testimony, to be followed by a summary of the staff testimony, itself to be followed a discussion of GSU's supplemental rebuttal to the staff consultants.

Several witnesses compared River Bend's costs to those of other plants. The gist of their testimonies was that regression analyses are subjective and unreliable, that they should not be used to determine prudence, and that in any event accurate comparisons showed River Bend not to be unduly expensive.

Dr. Marshall took issue with Mr. Komanoff's statistical comparison of plant costs. He characterized it as "results-based" and considered it inappropriate for the calculation

of any disallowance because it did not identify any specific imprudent action or decision. Dr. Marshall observed that the unexplained difference between River Bend's actual and its expected cost could be attributable to factors outside GSU's control yet excluded from Mr. Komanoff's model. He also testified that Mr. Komanoff's results should be expressed as a statistical range, to wit, "There is a 95 percent probability that the predicted costs of constructing River Bend lie between $1702 per kW and $3847 per kW."

Mr. Koppe discussed a number of problems inherent in regression analysis. He pointed out that there are "hundreds of different design factors which can and sometimes do affect plant performance." Thus selecting the "right" variables is a nigh impossible task. Nor can statistical analysis in any way show cause and effect between independent and dependent variables.

Mr. Koppe also attempted to rebut Mr. Komanoff's specific analysis of River Bend's actual costs compared with those of other plants. Mr. Koppe argued that plants with later construction permits were affected more significantly by burgeoning NRC regulations than plants with earlier permits. He offered two very simple comparisons of two or three plants with similar characteristics which showed the later plants to be the more expensive. He also emphasized the impact of QA requirements on later plants.

Mr. Koppe argued that per kW comparisons ignored economies of scale. In other words he contended that a larger plant (e.g. 1200 MW) would cost less per kW than a smaller one (e.g. 940 MW). He also took issue with Mr. Komanoff's analysis of the cost savings associated with two-unit plants. Finally, he disputed Mr. Komanoff's contention that regulatory delays during construction add substantially to plant costs. Therefore, he concluded, Mr. Komanoff's stop-work variable was inappropriate.

Mr. Koppe also offered two alternative regression analyses. In those analyses, he added two plants, Shoreham and Seabrook, to Mr. Komanoff's stop-work category. He also added a variable for percentage of construction reported to be complete at the end of 1979, on the theory that construction performed during the 1980s was more expensive. In the second of his analyses he eliminated two low-cost-per-kW plants, Summer and St. Lucie, because they were considerably cheaper than his observations on the effect of plant size on per-kW costs would have led him to expect.

The first regression reached an expected cost of $3125/kW for River Bend, the second an expected cost of $3646/kW, compared to its actual direct cost of $3680/kW. Mr. Koppe emphasized, however, that he did not think statistical analyses of this type were to be trusted. In fact, on redirect examination he described such analyses as a "glorified shell-game." Tr. Vol. 78 at 12103.

On cross-examination Mr. Koppe admitted that the percentage-complete variable was somewhat subjective because plants reported those percentages in different ways and because the percentage complete could even decrease in succeeding years due to changes in plant scope or regulatory requirements. He agreed, for example, that River Bend, which was much farther from completion than STNP in 1979, had caught up in 1982. He maintained, however, that the reported percent complete variable nevertheless offered a fairly reliable measure of relative construction status in 1979. Id. at 12055-58, 12086-87, 12112-15.

In the regression analyses, direct costs of plant, excluding AFUDC, are used for comparison purposes. Yet Mr. Koppe also agreed that the work stoppages at Seabrook and Shoreham had occurred with construction virtually 100 percent complete. Id. at 11957-60. Seabrook and Shoreham are not experiencing significant new direct costs. Mr. Koppe also observed that Comanche Peak was

undergoing documentation problems of the same general type as Zimmer. Id. at 11955.

Mr. Cahill of GSU argued that River Bend should be compared only to other BWR Mark III plants: Grand Gulf (1250 MW), Perry (1205 MW), and Clinton (950 MW). Using figures supplied by Mr. Houghton's consulting firm, he concluded that River Bend's costs were higher than Grand Gulf's but less than Perry's or Clinton's. Mr. Cahill's chart showed Perry's direct cost *per kW* to be lower than River Bend's, however. Mr. Cahill also stated that River Bend had exceeded its estimate by 2.59 times, while others had exceeded their estimates by as much as 4.3 times. Mr. Cahill did agree that River Bend's was the last of those estimates to be performed, which would help to explain why its increase in cost was relatively less. Tr. Vol. 89 at 13889.

The NERA panel, substituting at the hearing for Dr. Perl, criticized Mr. Komanoff's analysis as ignoring a number of "key cost determinants." Dr. Perl added the following variables:

1) single unit BWRs;

2) plants built by utilities simultaneously constructing several nuclear plants and operating as their own constructors; and

3) percent of construction complete as of TMI.

Inclusion of those raised River Bend's predicted cost to $3638 per kW, only 1.2 percent below its actual cost as measured by Mr. Komanoff. Once those variables were included, two of Mr. Komanoff's variables—cooling tower and Northeast location—were no longer significant at the 80 percent level. While there was "no hard and fast rule," one could argue that those variables should be dropped. GSU Ex. 265 (Perl test.) at 6. Dropping both would increase River Bend's predicted cost to $4053/kW. Further removing the stop-work variable would increase the cost to $4223/kW.

Dr. Perl included the single unit BWR variable because, other things being equal, such plants have cost "31 to 46 percent more to complete than PWRs or multiple unit plants." Mr. Komanoff had argued against that variable on the ground that it unreasonably penalized ratepayers for problems in BWR design and/or construction. The utility-as-constructor variable encompassed two utilities, Duke Power and Commonwealth Edison. Plants within that group experienced costs 24 to 34 percent less than others. In discussing Mr. Perla's unfiled cost analysis, Mr. Komanoff had rejected a similar variable, arguing that inexperience or an inability to control one's constructor should not excuse poor cost performance. Dr. Perl also found that costs were reduced 3 to 5 percent for each 10 percent increase in the percentage of a plant complete at the time of TMI. Mr. Komanoff had observed no significant variation. In Mr. Komanoff's opinion, plants which were farther along met fewer requirements, but those requirements called for more expensive solutions.

Dr. Perl believed his additional variables were logical. BWRs experienced unanticipated engineering and construction difficulties, which affected single units more significantly on a per/kW basis. Nuclear experience and economies of scale would lower plant costs. The 1979 TMI accident served as a landmark, after which the NRC began imposing more and more stringent QA requirements. He observed that prudent management could not have reversed the consequences of those variables.

Dr. Perl took issue with the stop-work variable used by Mr. Komanoff. He pointed out that Comanche Peak received no stop-work order. He also felt that inclusion of the variable was unfair. It compensated for the high costs of plants with allegedly poor management, but not for the low costs of plants with superior management.

Finally, Dr. Perl did not believe that cost comparisons could be used to determine prudence. At best they pro-

vided "a rough screening process" to determine whether a more rigorous prudence review is necessary.

On cross-examination it was established that Dr. Perl had not included Perry and Grand Gulf, both of which had per-kW costs below River Bend, in the single unit BWR category. Both are in fact single units, however. As Ms. MacMullen explained,

> For Perry, the second unit has been canceled. When we initially did this work, we did not include it as a single BWR because we weren't sure how the costs were being treated for Perry-1, and also because Perry was constructed for most of its construction period as a two-unit plant. For Grand Gulf, the second unit has not been canceled, so it's still in effect a multi-unit project.

Tr. Vol. 118 at 18470-71.

Messrs. Mattson, Booker, Curless and Koppe discussed the causes of cost increases at River Bend. Their views have already been discussed at some length. Dr. Mattson and Mr. Booker emphasized increased QA requirements and regulatory scrutiny. They rejected Mr. Beckham's testimony that QA costs should not have increased significantly if an adequate program had been in place. Mr. Koppe made much the same arguments. He was vociferous in his characterization of many of the new NRC requirements as unnecessary and "bureaucratic." He also cited a 1982 NRC report which attributed 30-35 percent of the cost of a U.S. nuclear unit to QA requirements. Mr. Curless defended the IEF's coding system. He stated that its nine reason-for-change categories were not developed to facilitate detailed after-the-fact analysis of causes, but merely to group all changes into basic categories. He disputed OKA's assertion that only $378 million was identified in the IEF as regulatory change.

Mr. Booker contested MHB's analysis as to the timing of GSU's decision to implement the concrete annulus fill

to resolve Mark III load issues. He emphasized differences between Perry and River Bend, stating that it would have been unwise to proceed with the annulus fix at River Bend without a plant-specific analysis. Moreover, it was not imperative to reach a quick decision at River Bend, since Perry was further along in its construction. GSU was able to wait to pursue an engineering solution and to benefit from Perry's experience. He testified that the actual cost of the concrete fill, when implemented, was only $4 million. He also testified that the timing of the decision caused no delay. MHB's 2-month figure was based upon milestones under the 50-month schedule, which was extended to 68 months for financial reasons. He rejected MHB's view that GSU should have authorized GE's New Loads Adequacy Evaluation of River Bend in 1977. He considered it to have been prudent, given the construction hiatus, to have waited for further definition of the loads problem. According to Mr. Booker, the ARS error discussed by MHB played no part in GSU's decision. That was, in fact, a minor problem. Mr. Booker also labelled as "simply untrue" MHB's contention that the timing of the annulus fill decision caused delays in piping along with equipment requalification and much reanalysis,

> Such delays occurred at some other Mark III plants since those plans were under construction well before River Bend. However, that was not the case at River Bend.

GSU Ex. 203 (Booker rebuttal test.) at 12.

He argued that the notion of significant delays at River Bend did not make sense, as River Bend, unlike other BWRs, was constructed in record time.

Mr. Sobon, in his discussion of Mark III issues, agreed with Mr. Booker's conclusion that postponement of the NLAE allowed River Bend to benefit from other companies' experience. According to Mr. Sobon, other utilities had to continually reevaluate data.

> Those utilities that authorized the NLAE before 1979, had to restart much of the analysis due to changes in methodology and load definitions. By suspending River Bend construction from March 1977 to February 1979 and by not authorizing the NLAE until 1979, Gulf States avoided many of the repeated iterations that took place during this period.

GSU Ex. 213 (Sobon rebuttal test.) at LJS-2, p. 18.

Mr. Sobon also testified that in February 1979 the NRC established a Seismic Qualification Review Team (SQRT) to evaluate generic aspects of dynamic loads on equipment for both PWRs and BWRs. The existence of the hydrodynamic loads program mitigated the impact of the SQRT review on BWR plants.

> Because of the timing of the work, relative to percent completion of plants in 1979, this increased SQRT work would have impacted the cost and schedule of Mark III projects in much the same way that the hydrodynamic loads did. In the case of River Bend, there was even a lesser impact.

Id. at LJS-2, p. 29.

Mr. Cahill stated flatly that Mark III issues did not cause any delays in the construction schedule. The containment structure was completed on time. The only impact of Mark III on construction was the annulus fill in mid-1981. That activity cost only $4 million and did not delay other construction work.

Mr. Schultz also testified that Mark III caused no construction delays and that the $4 million cost would have been incurred regardless of the timing. Mr. Schultz further testified that the 50-month schedule did not add any cost to the project. He criticized the River Bend CASAR as having been prepared by S&W personnel not associated with design and construction of the

plant. Moreover, he stated, the $45 million identified in the CASAR would have been spent regardless of the length of the schedule. He believed that "the same vendor requirements and construction needs would have existed." Yet he also testified that vendors' inability to support the construction schedule led to field fabrication of reinforcing steel, pipe, and pipe supports along with associated engineering and procurement support. GSU Ex. 191 (Schultz rebuttal test.) at 3435.

Mr. James Deddens and Dr. Mattson testified on TDI issues. Dr. Mattson observed that the NRC's own inspections of the TDI manufacturing facility in the early 1980s did not alert the Commission to the possibility of major engine inadequacies. Those were not revealed until the Shoreham incident in 1983. He pointed out that the NRC has not faulted any utility's QA program for the TDI problems. He believed that while the "generic nature" of the TDI problem did not relieve GSU of its responsibility for TDI's actions, "there are special circumstances which absolve GSU and other utilities of potential wrongdoing or imprudent management." GSU Ex. 193 at 4-14. The NRC's failure to blame any of the utilities which purchased TDI diesels supported that analysis.

Mr. Deddens rejected MHB's claim that the TDI problems resulted in delays and costs in excess of out-of-pocket expenses. He described GSU's TDI-related activities and testified that requalification of the diesels did not delay fuel loading or any other testing program. He rejected the argument that GSU should somehow have prevented the problem. In his view MHB was confusing QA with design review. Mr. Deddens also testified that the direct costs attributable to TDI problems totaled $8.1 million, not $10.5 million. The higher figure was based upon a draft estimate which had double-counted one item of expense. GSU Ex. 184.

The arguments over GSU's control and management of S&W have also been discussed in some detail. Some

new points were raised on rebuttal, however, Mr. Fawcett of MAC testified that GSU was very responsive to the findings of the 1976 MAC "Mini-Diagnostic." In particular it hired Mr. Humphreys to take charge of the project and began to implement and staff an adequate project organization. He recognized that MAC in 1978 had referred to GSU's project management state as "embryonic", but believed that could have been said of most nuclear utilities. He testified that GSU was prepared to proceed with River Bend. Theodore Barry and Associates' January 1979 report found, in Mr. Fawcett's words, "that Gulf States had assembled a strong management team and that a transition toward greater control of the power plant construction program was proceeding rapidly." GSU Ex. 195 at 27. Mr. Fawcett considered the River Bend Nuclear Group formed in November 1979 to have been very effective.

Mr. Glazar took issue with Mr. Stiles' observation that April 1980 assignment of GSU engineers to CHOC was "too little, too late." During the hiatus period, no such assignment was necessary. In 1980, however, once the project was underway, the assignment to CHOC proved beneficial to GSU and S&W. The problems found in 1980 with EMS were problems typical of implementation of a new technologically advanced system.

Mr. Cahill identified steps taken by GSU to minimize and control project costs. First, a senior executive, Mr. Cahill, himself was placed at the site where he could more effectively oversee project activities. Second, the computerized cost control system, constantly updated, allowed GSU and S&W to plan work in a timely manner and provided needed detail. Moreover, any significant change in project scope, design, or cost had to be approved by GSU.

Finally, Dr. John Borcherding offered testimony as to productivity at River Bend in rebuttal to general charges of waste and inefficiency, particularly related to

TDI and Mark III. He found construction productivity, based on work sampling, to have been excellent. He also found that GSU had implemented effective work force management (WFM) programs. It had implemented 52 of 57 elements which could be incorporated into a WFM program. He also observed that poor productivity is usually accompanied by project delays.

The luster of Dr. Borcherding's testimony was dimmed somewhat by his failure to provide some of his workpapers. Some of his testimony, not discussed here, was stricken as a consequence of that failure. The importance of workforce management programs, moreover, should be considered in light of the fact that a WFM includes relatively trivial items such as a project newsletter, a bulletin board, job picnics, and a logo program. Tr. Vol. 93 at 14566 *et seq.* (Borcherding cross.).

4. Staff Case

Mr. Hadzi-Pavlovic of DMC and Dr. Pflaum of QED presented the staff case. DMC evaluated in detail the $74,800,000 in costs identified by OKA as wasted on the 50-month schedule. It agreed with GSU that the money would have been spent anyway, although at a slower rate. For example, engineering man-hours would have been spent to design the plant in any event.

DMC concluded that neither PLG nor OKA had adequately supported its contentions regarding the amount of cost increases attributable to regulatory changes. It found no evidence that PLG investigated reasons for change beyond a general affirmation that regulatory changes were significant. In cross-examination Mr. Hadzi-Pavlovic stated that a far more complete and accurate investigation of the reasons for cost growth was possible, though difficult. He described the process in detail. He emphatically rejected Dr. Mattson's contention that factors such as greater scrutiny and documentation requirements "defy estimation and quantification." Tr. Vol. 112 at 17551.

DMC believed that OKA delved into the question of cost growth in much greater detail than did PLG. OKA's report did suffer from flaws and inconsistencies, however. In addition, OKA did not assert that the difference between its calculated regulatory cost figure and GSU's was attributable to imprudence.

DMC did believe that PLG's attribution of 46 percent of River Bend's cost growth to regulatory changes appeared reasonable compared with experiences at other plants. It concluded, however,

> that the testimonies of neither GSU nor the Parties offer sufficient evidence to enable the PUCT to make a finding of either prudence or imprudence regarding either the causes or reasonableness of increases in the cost of River Bend since the Definitive Estimate.

DMC rejected MHB's position on the Mark III concrete annulus fix. DMC emphasized the lack of clarity in regulatory direction, the possibility of an analytical solution to the loads problem, and the importance of plant-specific studies. DMC rejected the contention that "superficial similarities" between Perry and River Bend should have prompted GSU to implement the annulus fill in 1979.

DMC stated that the concrete fill could not have been implemented until GE finalized new loads definitions in March 1980. At that time GSU hired a consultant who informed it that conventional analysis would confirm the adequacy of piping and equipment if the annulus fill was accomplished. GSU decided to proceed with the fill in June 1981 and finished the fill in September 1983, within its construction schedule.

DMC was uncertain whether the ARS error was justified, though it suspected it was a legitimate engineering mistake. In any event, DMC believed that the error had no bearing on the timing of the annulus fill. Finally

on that issue, DMC considered MHB's quantification of Mark III costs to be "seriously flawed." MHB did not address any specific impacts of Mark III on the River Bend critical construction path.

DMC found GSU to have been prudent in its handling of the TDI diesel problems. According to DMC, GSU's and S&W's quality assurance program complied with the standards required by law. The NRC did not find fault with GSU or any other utility or architect-engineer. After the problem was identified in 1983, GSU helped form the TDI Owners' Group and vigorously pursued solutions. DMC recommended, however, that the Commission exclude from rate base the $10.5 million in direct costs attributed by GSU to the TDI problem, pending resolution of GSU legal claims against TDI.

DMC rejected MHB's claims of a $54 million disruptive impact from TDI. It concluded that while some indirect costs were undoubtedly incurred, "it is wholly without merit to levy a $54 million penalty on GSU for having had a problem and solving it."

Dr. Pflaum presented another statistical analysis of River Bend costs in response to those of Mr. Komanoff and Dr. Perl. He believed there to be presumption of prudent management, which can be rebutted in one of two ways: by a demonstration that imprudent decisions were made and that these had a cost impact; or by a showing that the capital cost associated with the investment in question is inexplicably high. In the second approach, if actual costs are "far removed" from a project's reasonably expected cost, the utility should have to provide a detailed explanation of the reasons for that higher-than-expected cost.

Dr. Pflaum emphasized in presenting his statistical analysis that there should be a logical explanation for the use of any particular independent variable. Simple correlation to higher cost would not be enough if the variable did not make sense. Dr. Pflaum included the

variables agreed to by both Dr. Perl and Mr. Komanoff as well as Mr. Komanoff's work stoppage variable and Dr. Perl's utility-as-constructor variable. He specifically excluded Dr. Perl's single unit BWR variable. He did not include a variable for either construction permit date or percentage complete in 1979.

On the utility-as-constructor variable Dr. Pflaum observed that it would be unfair to expect GSU to perform nuclear construction as efficiently as Duke Power or Commonwealth Edison. Those companies have vast internal resources and greater experience, as well as the ability to benefit from economies of scale and to use similar designs for multiple plants.

Dr. Pflaum considered the stop-work variable reasonable as well. He stated that "very few plants have encountered the complete breakdown of the Quality Assurance/Quality Control process that leads to an NRC-mandated stop-work." Lifting such an order can be very expensive. He observed that the stop-work variable, which recognizes unusually bad performance, was the "other side of the coin" from the utility-as-constructor variable. Dr. Pflaum removed Comanche Peak from the stop work group, however, because it had not received an NRC stop work order. Tr. Vol. 107 at 16758-59 (Pflaum cross.).

Dr. Pflaum eliminated the single unit BWR variable. He originally said that it double-counted, since another of Dr. Perl's variables was the number of units at the site. He later agreed that he was incorrect in that belief, however. Dr. Pflaum ran the regression model with a simple BWR variable, which proved to be statistically insignificant. He offered several hypotheses for the significance of the single unit BWR variable as opposed to the simple BWR variable. He mused that BWR technology may have been especially attractive to "nuclear neophytes," that there may have been a Stone & Webster factor (S&W built several single unit BWRs), or that a

number of the single unit BWRs were originally planned as multiple units.

Dr. Pflaum did not explain in his prefiled testimony why he did not use a variable for percentage complete as of TMI or construction permit date. In cross-examination, however, he suggested that he did not because of contraditions between Mr. Perla's and Dr. Perl's interpretations of the effect of TMI on plants under construction.

Dr. Pflaum's estimated cost for River Bend was $2590 per kW, 33 percent below its actual cost. Dr. Pflaum testified, however, that

> Statistical evidence is not a proper basis for a regulatory determination of prudence. The data associated with plant cost is necessarily messy and inter-utility comparisons are difficult to make. We do believe, however, that a statistical analysis such as we have performed is valuable in establishing the degree to which a utility should have to bear the burden of proof with respect to the justification of costs.

Staff Ex. 58 at 30-31.

Despite his considerable suspicion as to the accuracy of the results of statistical analysis, Dr. Pflaum recommended that 33 percent of GSU's River Bend investment be held in suspension until GSU could prepare and present adequate documentation and explanation for cost growth. He based that recommendation upon Mr. Hadzi-Pavovic's belief that River Bend's costs were unexplained. He recommended that GSU be allowed to accrue return on its books on that suspended portion.

5. GSU Supplemental Rebuttal Case

In supplemental rebuttal to the staff, Mr. Traylor of MAC took issue with Dr. Pflaum's suggestion that 33 percent of GSU's investment in River Bend be placed in

abeyance pending further explanation. He observed that Mr. Hadzi-Pavlovic had not stated that River Bend's costs were "unexplained," but rather that there was no detailed correlation between specific costs and specific regulatory causes. Mr. Traylor believed that a detailed reconciliation of the kind described by Mr. Hadzi-Pavlovic would be very time-consuming and virtually impossible with "even the most sophisticated methods, with unlimited resources, and the most detailed cost records." He stated that the 46 percent figure assigned to regulatory change, and believed by Mr. Hadzi-Pavlovic to be reasonable, was low based on results of other industry studies.

Dr. Marshall stated that Dr. Pflaum's statistical results should be expressed as a 90 percent probability that the cost of River Bend would be expected to be between $1946/kW and $3447/kW, with a mean of $2590/kW. If River Bend had cost 0.2 percent less ($6.89/kw), it would lie within that range.

Dr. Perl, not surprisingly, disagreed with Dr. Pflaum's conclusions. He considered Dr. Pflaum's reasons for excluding the single unit BWR variable to be specious. He stated that the evidence showed BWRs to be more expensive that PWRs. He criticized Dr. Pflaum for failing to include, without explanation, the percent-complete variable. He ran the model using Dr. Pflaum's variables plus that one. In that permutation River Bend exceeded its expected cost by approximately nine percent. In reaching that result he had eliminated the Northeast variable, which was not statistically significant in conjunction with those others. With the Northeast variable included, River Bend exceeded its expected cost by 18 percent.

6. Examiners' Recommendation

The examiners agree that, in the absence of evidence to the contrary, it is reasonable to presume that the utility has built its nuclear facility in a prudent fashion. In this case that presumption is rebutted by the admittedly high

unadjusted cost of River Bend compared to other plants. It is up to GSU, not the intervenors, to justify these costs either by a detailed reconciliation of cost increases with legitimate reasons or by reliable statistical analysis. GSU must explain why River Bend is the fifth most expensive plant, per kW, in the United States.

Dr. Weigand of GSU observed, according to the PLG interview notes, that "GSU doesn't know why River Bend cost so much." [8] OPC Ex. 32 at 173. That appears to be the case. GSU did not present any credible reconciliation of plant costs with specific causes, much less with specific regulatory changes. Even if the causes for change were legitimate, it did not show that the amounts of money spent to meet various goals were reasonable. It did show more generally than regulatory changes had a dramatic effect on the project's scope and cost. Yet from the evidence one cannot tell how wisely and efficiently money was spent on design development, scope changes, and meeting regulatory changes.

The examiners find that $74,680,000 were imprudently spent in attempting to achieve the 50-month schedule and that pursuit of the schedule reduced construction productivity. They find specific though unquantifiable imprudence in S&W's engineering performance during the 1979-80 time period. They further find that $8.1 million in TDI costs should be disallowed not because of imprudence on GSU's part but because of TDI's imprudence, for which GSU, not its ratepayers, should be ultimately responsible.

Almost against its will GSU presented statistical evidence to contrast River Bend's costs with those of its contemporaries. The examiners agree with GSU and the staff that regression analysis is inherently subjective and its accuracy suspect. Nevertheless, it is the only means

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[8] The quotation is from PLG's notes. Those were not necessarily Dr. Weigand's exact words.

available, in this case, to measure the costs of River Bend against those of other plants while taking into account the inherent differences between them and thereby adjusting for River Bend's handicaps and advantages. The examiners find the most credible of those analyses, that with the most reasonable set of variables, to be Dr. Perl's presented in supplemental rebuttal to Dr. Pflaum. They therefore recommend that nine percent, or approximately $274,050,000 of GSU's approximately $3.045 billion investment in River Bend, be disallowed. The specific examples of imprudence described above should be captured by the statistical analysis. Therefore their costs should not be added to the nine percent, but should be separately excluded only if the Commission believes that regression analysis is too blunt a tool.

The specific reasons for the examiners' recommendations are discussed below:

a. *Cost reconciliation.* The examiners found the PLG Report to be extremely superficial. Its analysis of the reasons for changes in the cost of River Bend was very cursory. PLG simply took the summary of reasons from the IEF and repeated them. That approach was seriously flawed for many reasons. First, as the testimonies of Mr. Curless and Mr. Schultz showed, the IEF was primarily a cost tracking and accounting tool. It was not really designed to provide a detailed justification of cost increases. Its reason-for-change feature involved nine "basic generic" codes. Those offered no clue as to the reasonableness of changes or the amounts spent making those changes. In fact in explaining costs those categories were so broad as to be almost meaningless. The fact that a change was attributed to "design development" for example, tells nothing about why the design had to be developed or how much that process should have cost.

Certainly PLG's investigation offered no insight on that score. PLG examined literally a "handful" of the

WPCNs coded into the IEF, and those only for form, not for substance. Tr. Vol. 21 at 3252-53. It is of some comfort that GSU had a legitimate process for reviewing and approving changes in project cost, but that alone does not show that those costs were reasonable, unless one is willing simply to take GSU's word for it.

The guidelines for coding changes to the regulatory category limited the informative value of the IEF. Any changes to Category 1 (safety-related) structures were coded as regulatory. The fact that costs changed for a structure subject to NRC safety standards does not mean that the cost increase itself was prompted by regulatory changes, however.

Use of the IEF without further investigation to explain cost changes ensured, moreover, that every change appeared to be justified. Every change, after all, was categorized. Obviously incompetence, inefficiency, and imprudence were not among those categories.

Mr. Perla admitted that PLG had performed more thorough audits in other cases. Its report cost GSU approximately $300,000, as compared with approximately $2 million spent auditing the Perry plant. Tr. Vol. 19 at 2998-99 (Perla cross). Of course the cost of a study alone is meaningless, but in this case the difference between the figures accurately conveys the lack of depth of the River Bend report.

Finally the PLG Report's credibility was damaged by the absence of a cost-per-kW comparison. In other cases PLG has cited low cost per kW as an indicator of prudent management. In Palo Verde, it was a key measure of performance. In this case, however, PLG cited River Bend's rapid construction schedule and better than average productivity, and dodged the cost-per-kW issue. Even the productivity comparisons were suspect. OPC pointed out through cross-examination that River Bend used more quantities for eight out of eleven commodities and more man/hours for seven out of eleven commodities. Tr. Vol.

21 at 3338. In that light its relatively good ratio of man/hours per commodity unit is less impressive.

The OKA Report, presented for the PPC, was much more thorough. It reached no conclusions as to imprudence during construction, however, except as regards the 50-month schedule. OKA never suggested that the $445 million for which there was "inadequate documentation" was imprudently spent. It did not recommend any disallowance on that score. In fact, its one- or two-sentence summaries of the WPCNs and MCCs suggested to the examiners that the changes were valid. Moreover, Mr. Roosevelt on cross-examination of Mr. Winn was able to identify some lapses in OKA's review and characterization of the WPCNs and MCCs.

As Mr. Hadzi-Pavlovic pointed out the evidence does suggest that GSU's attribution of 46 percent of cost growth to regulatory causes figure is not unreasonable. Other industry studies found greater effects. That fact alone does not prove the 46 percent figure correct, but it does offer some support. Dr. Mattson, Mr. Booker, and others also proved to the examiners that unforeseen regulatory requirements did have a significant if unquantified effect on plant costs. Quality assurance requirements and general regulatory scrutiny were particularly significant. Mark III engineering costs and ASME-NF piping standards—neither of which were post-1979 regulatory changes, but neither of which could have been accurately estimated at the time of the DCE—also were significant. The examiners did not agree with Mr. Beckham that a proper QA program would have cost the same regardless of more frequent inspections and greater documentation, or that regulatory scrutiny after TMI should be discounted.

Mr. Glazar's listing of design features unique to River Bend was unconvincing as an explanation of the plant's cost. He did not attempt to quantify those costs. The

examiners agree with OKA that the cost of those features was relatively insignificant.

In sum, however, the examiners agree with staff consultant DMC. GSU's non-statistical explanations of the reasons for cost growth at River Bend were inadequate and unconvincing. If that was the only type of evidence in the case on that subject the reasonableness of that growth would remain a mystery and the very high cost of building River Bend would remain, for the most part unjustified.

b. *Specific incidents of imprudence.* The examiners have found the 50-month schedule to have been imprudent. They also find that at least $74,680,000 million was imprudently spent in pursuit of that schedule. The River Bend CASAR and contemporary documents belie the argument that those costs would have been incurred anyway. The CASAR, an S&W document, shows $45,777,000 in schedule-related costs, without AFUDC. It also states,

> When the project was reactivated, construction and planning personnel began to reschedule the construction activities to support a 50-month construction schedule. As this effort was completed, the new field-required dates were interpolated into the engineering schedules. Since the new accelerated schedule required drawings to be issued and material to be available onsite much earlier than previously anticipated, a crash program was undertaken by headquarters personnel to meet this challenge.
>
> The initial effort, which involved engineering, planning, contracts, and purchasing groups, was to renegotiate all contracts and purchase order to support the new schedule. This was an intense effort, but was compounded by the previous renegotiation which had taken place with the vendors for the purpose of delaying the delivery schedules. To expedite the effort, the 140 purchase orders to be negotiated were divided into three priority groups, each with a target

date for finalized negotiations, resulting in purchase order changes. The difficulty of this effort was typical. Each vendor had his own set of problems; some used the schedule change to try to get price relief; others had committed shop space to other jobs due to the previous delay and had to resort to premium time to meet the schedule.

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A $38,214,000 cost increase since the September 1979 estimate was attributed to schedule impacts. These costs were directly related to efforts to support the accelerated schedule developed with the new construction contract. Renegotiations with vendors were taking place in order that equipment and material deliveries would support the new field-required dates on the 50-month construction schedule. In cases involving the inability of the fabricator to meet the new schedule, some of the work was transferred to the S&W force account (i.e., rebar, piping, and supports) and shop overtime was used (i.e., valves). In areas where the field-required date could not be met and equipment could not be installed after completion of construction, redesign of slabs was initiated to allow for openings so construction could proceed (i.e., control building).

Dr. Weigand observed, in a memorandum to Mr. Cahill on October 27, 1980:

We are currently paying premium costs for expediting PGCC manufacture and testing. These added costs are necessary to meet the current construction schedule which requires delivery of the PGCC in December 1981. The latest S&W construction reports show that the control building construction effort is six weeks behind. Additionally, there has been no recent improvement in this path and, if anything, the indications appear to be that this slippage will continue to grow.

> If it is reasonably probable at this time to project six or more weeks slippage in the control building structural effort, it is possible that a substantial sum of money can be saved by rescheduling work on the manufacture and testing of the PGCC. Also, we are currently looking at plans to do additional testing of the PGCC, in particular the process computer, which would be facilitated and also could be done at a lower cost if we could delay shipment to the site.
>
> There are many other areas were we have incurred extra costs by expediting the manufacture or testing of equipment and materials to meet the 50-month construction schedule. If any construction path becomes significantly altered, it is important that we act promptly to realize whatever savings are possible. It is going to be difficult to judge when the odds of recovering schedule are too high to continue with expensive expediting, but it is certain that our public service commissions will expect us to do this.

Those observations do not imply that costs associated with the 50-month schedule would have been incurred anyway. While that may be true of many of the headquarter man-hours spent designing the plant, GSU has not proven how much money would have been spent and how much not. Therefore it should be held responsible for the entire $75 million.

The examiners also find that S&W's engineering effort was inefficient to the point of wastefulness during the first year or so of the project. Mr. Allen's letter to Mr. Crawford admits that inefficiency and attributes S&W's problems to the rapid resumption of plant construction.

> As you know, we have exerted a major effort to marshall our engineering resources to this project after your reactivation of the work 17 months ago. The magnitude of this taks [sic] should be evidence when one considers that the staff of approximately

200 engineers and designers in January, 1979, was tripled within six months and quadrupled by the end of the year. A significant portion of the Cherry Hill effort is being accomplished on a heavy overtime schedule varying from 8 to 18 hours per week. Under such workload, some efficiency loss is unavoidable (the EMS performance index for the month of May shows 86 percent effectiveness). We fully expect an improvement in efficiency as overtime is phased out and the project staff is reduced in 1981.

Mr. Lee stated that pursuit of the 50-month schedule also reduced construction productivity.

Q: Are you telling me, Mr. Lee, that if you had additional financing so that you could support more people on the job, you could not have completed the project more rapidly?

A: At that time in 1981, [the time of the schedule extension] it was my opinion that we could not catch up the slack regardless of pouring more money in it, for two reasons. One is, the more people we put on it, the lower the productivity became per man-hour. The second reason was, it becomes so many people they got in each other's way in working.

• • • •

Q: In March of 1981, did GSU cut back its nonmanual work force from 2,300 workers per shift to 1,700?

A: Over a period of time, yes.

Q: Was the reason in March of 1981 for the cutback in the number of nonmanual employees because of financial constraints?

A: It was cut back because of two things. One is, there was no use in spending extra money if the productivity wasn't there. We were getting

about as much work output from the reduced number as we did the increased number. We were trying to find the level at which the optimum production per man-hour was there.

Tr. Vol. 58 at 9097-98 (Lee cross).

Engineering Management System was in disarray through at least 1980. The 1980 audit shows that plainly. The 1980 audit stated,

> From September through November our representatives in Cherry Hill conducted an audit of EMS workpackages. While the audit did not cover all areas, it was comprehensive in the workpackages examined. The recurring problems discovered are indicative of several basic problems which are of concern to GSU and require intensive effort for timely resolution. We are aware that S&W has simultaneously pursued a parallel audit and has initiated certain actions to improve the effectiveness of EMS on the River Bend project. GSU is concerned that excessive time has elapsed between the uncovering of EMS problems and the commencement of corrective action.
>
> • • • •
>
> GSU is most concerned that the logic contained in the PMS network files upon which we rely for accurate planning and schedule tracking in many instances does not reflect the actual work. Therefore, the reports which track progress cannot accurately reflect the actual progress of performance.
>
> • • • •
>
> It was found that the training of EMS users was apparently deficient in that the users had problems in understanding or using the system in the following areas:
>
> a. The users did not believe in the system because of the problem discussed in Item I.

b. Detailed knowledge of how the system works as provided by the current EMS courses was inadequate.

c. What reports are available and which specific reports and combinations of reports should be in daily use was not understood.

d. EMS reports were not being used to plan future activities.

e. The extent of use of the system by the workpackage engineer was primarily in monitoring the work of his own discipline, or with other disciplines only when a workpackage analysis report was required.

• • • •

The training must also emphasize that the logic changes necessary to pursue a 50-month schedule require S&W engineers to work carefully with the planners to insure that new logic not only supports their responsibility, but also the needs of other disciplines. The project is too complex to be efficiently managed by manual means.

• • • •

For the River Bend Project, the Engineering Management System (EMS) was retrofitted effective June 1, 1979, to provide a computerized reporting system and for management control over remaining Headquarters' man-hour and schedule. As of July 31, 1979, S&W was reporting 67.2 percent complete for Headquarters based on manual estimates. . . .

To date, GSU has not been able to substantiate Engineering percentage complete.

The audit observed that problems with EMS were aggravated by the 50-month schedule. The 1982 audit found improvement, but also acknowledged continuing problems with the system. At least partly because it

could not keep track of engineering status through EMS, GSU put its own engineers at CHOC.

The problems with EMS deprived GSU of a valuable tool for project control. Trying to resolve the problems also took time and money. Unfortunately the problems with EMS, S&W engineering inefficiency, and the reduction in productivity from pursuit of the accelerated schedule generally cannot be quantified accurately.

The examiners find no evidence that GSU or S&W was imprudent in the handling of TDI problems. Mr. Hubbard's testimony was not based upon any flaws in their QA programs, but simply on the premise that the NRC lost confidence in the diesels, so GSU must have been imprudent. *See* Tr. Vol. 62 at 9636-37, 9669-70. The examiners do not agree. The continual problems at TDI, culminating in the failure at Shoreham and the NRC's loss of confidence, suggest that TDI itself was imprudent, however. GSU,not its ratepayers, should have to bear the consequences of TDI's actions. The direct costs of TDI problems totalled $8.1 million. Although other expenses were probably incurred in resolving the problem, MHB's calculation of an additional $54 million in "delay costs" was arbitrary and unsupported by any documentation.

Obviously Mark III problems cost something, but no one, including GSU, knows how much. The examiners find that GSU's handling of the Mark III problems, including the concrete annulus fill, was prudent. GSU showed convincingly that Mark III caused no construction delays at River Bend. The annulus fill itself cost only $4 million. MHB's delay estimates were extrapolated from the 50-month schedule, which was extended for reasons completely unrelated to Mark III. Moreover, MHB's calculation of $300-500 million in total post-1979 Mark III costs was completely unsupported and cast doubt on its entire analysis of the issue. MHB seemed determined to find costs similar to those at other plants, re-

gardless of the obvious differences between River Bend, Perry, and Clinton. The evidence also did not show imprudence on the part of GSU, S&W or GE with regard to the Mark III problems.

The costs of the 50-month schedule, engineering, construction, and EMS inefficiency, and TDI should be captured in the statistical analysis described in the previous section. Therefore the $74,680,000 in schedule costs, $8.1 million in TDI costs, and the other unquantifiable costs should not be added to the examiners' proposed nine percent disallowance based on statistical analysis, discussed below. The existence of identifiable imprudence and inefficiency in the management and construction of the plant corroborates the exclusion of a portion of River Bend's capital cost from plant in service, however.

c. *Statistical analyses.* GSU contended that all plant costs should be presumed to have been prudently incurred. In GSU's opinion intervenors may use statistical analysis only to call that assumption into question. Even then the presumption would remain unchallenged unless the plant's actual costs were above the high end of the range of expected costs predicted by the statistical model.

The examiners do not agree with GSU's approach. GSU has the burden of justifying the costs of River Bend either by detailed analysis or by showing that those costs are reasonable compared with those of other plants. It failed to do the first. It succeeded fairly well in doing the second through Dr. Perl's rebuttal of Dr. Pflaum. That analysis, in which River Bend's actual costs were nine percent above predicted cost, incorporated the following contested variables:

1) stop work (including Comanche Peak)

2) utility as constructor

3) percent complete in 1979

It excluded the single unit BWR variable.

The stop work variable is appropriate because the purpose of the statistical analyses is to measure the variances in cost among prudently managed projects. It is reasonable to assume, solely for the purpose of making that comparison, that receipt of an NRC stop work order suggests poor management. It seems sensible to include Comanche Peak, which is undergoing a lengthy reinspection process, in the stop work category. Inclusion of the stop work variable should not be construed in any way, shape, or form as a finding of imprudence at STNP or Comanche Peak. Neither Houston Lighting and Power or TU Electric has had the opportunity or the inclination to present evidence in this docket.

The utility-as-constructor variable is indeed the other side of the coin. It would be inappropriate to expect GSU to perform as efficiently as Duke Power or Commonwealth Edison, with their far greater experience and resources, in the construction of nuclear power plants.

There was evidence on both sides as to whether NRC regulatory actions had a greater effect on plants well under construction or plants with farther to go like River Bend. It is at least plausible, given the testimony in the case, that plants which were not very far along were affected more seriously. If there were no correlation between cost and percent complete, moreover, the results of the regression analysis should not have changed. The intervenors have a point in saying that percentage complete can be a subjective and unreliable figure. It should, however, give at least a rough idea of the amount of construction left among plants in 1979.

Dr. Perl's single unit BWR variable was not appropriate for at least two reasons. First, Dr. Perl excluded Grand Gulf and Perry from his single unit BWR variable group. Yet Perry 2 has been cancelled and Grand Gulf 2 has been deferred indefinitely. Second, it is not clear how comparable River Bend is to other BWRs. Mr. Perl attributed high BWR costs to new loads problems.

Yet GSU spent much of its case proving that although Mark III problems were expensive River Bend did not suffer from the delays which plagued other BWR plants such as Perry and Clinton. Mr. Booker and Mr. Sobon both observed that there was no technical reason for BWRs to be more expensive that PWRs.

Dr. Perl's analysis, using the variables endorsed by the examiners, showed River Bend to be nine percent more expensive than its expected cost. The examiners recommend that nine percent, $274,015,889, of GSU's share of River Bend's cost be disallowed and excluded from plant-in-service.

The lengthy discussion between Mr. Avery and Mr. Komanoff, quoted on pages 105 through 107, on the subject of how a utility can demonstrate prudent management of construction, seems to militate against the conclusion reached by the examiners. Mr. Kamonoff's approach seemed to place before the utility an impossible task. That discussion itself was premised on two erroneous assumptions, however. The first assumption, which Mr. Avery stated explicitly, was that the utility has proved every disputed action or decision to have been prudent. GSU has done nothing of the sort. As was discussed above, the examiners find imprudence or inefficiency in GSU's pursuit of the overly ambitious 50-month schedule, in S&W's engineering efforts in the early years after the restart decision, and in the implementation of EMS. They also find imprudence of the part of TDI, though not on the part of GSU or S&W.

The second premise was that GSU can carry its burden of proof by showing its own statistical adjustments to River Bend costs to be unreliable. GSU's responsibility is to explain why River Bend cost so much. If statistical analysis is inherently inaccurate, GSU has not fulfilled that responsibility. It is not enough to say that River Bend's expected costs can be predicted within a range of a billion or so dollars, that one can have 90

percent confidence in that range, and to conclude that River Bend was prudently constructed because its actual costs were within that enormous range. Dr. Perl's rebuttal of Dr. Pflaum's estimate illustrates the point. Dr. Perl stated that Dr. Pflaum had miscalculated the 90 percent confidence interval. According to Dr. Perl, Dr. Pflaum's prediction of River Bend's estimated costs, would be from $1882 to $3565/kW if the correct interval were used.

Using the net capacity rating of 934 MW, that cost range translates into a direct capital cost, excluding AFUDC, between $1.758 and 3.330 billion. Dr. Perl testified that the difference between River Bend's actual direct cost ($3453/kW, or $3.225 billion) and Dr. Pflaum's calculated estimate ($2590/kW, or $2.419 billion) was not significant to the 90 percent confidence level because the actual costs were within that range. That may be, but it still does not explain why River Bend cost so much. GSU, which has the burden of proof, should not also have the benefit of the doubt simply because River Bend's cost was somewhat within the 90 or 95 percent confidence interval of the most reliable statistical analysis presented. Nor should it have the benefit of the doubt until the percentage deviation of River Bend's actual cost from its statistically expected cost reaches double digits.

Certainly statistical analysis is an imprecise measure, but it was the best one offered in this proceeding. The examiners find that the most credible analysis shows unexplained costs nine percent above what should have been expected for River Bend. GSU has failed to prove the prudence of those unexplained costs.

The other cost comparisons offered by GSU witnesses were not credible. Mr. Koppe, who did not believe in regression analysis anyway, excluded two low-cost plants from his regression analysis because they did not fit the patterns he perceived. Mr. Cahill's comparison of four

BWR-6 Mark III's was simplistic, particularly considering the differences in schedule between River Bend, Perry, Clinton, and Grand Gulf. It also showed River Bend to be second behind Clinton in direct cost per kW in real dollars.

As was mentioned in the description of Dr. Perl's testimony, his model showed a difference of 18 percent between River Bend's actual and expected cost with the Northeast variable included. Both Mr. Komanoff and Dr. Pflaum used that variable; Dr. Perl had used it in earlier models. He excluded it, however, because it was not statistically significant with the particular combination of variable he used in rebutting Dr. Pflaum. The other statisticians would also have omitted it on those grounds. Dr. Perl himself, however, admitted that there was no hard and fast rule. If the Commission finds that imprudence and inefficiencies in engineering or construction warrant a disallowance greater than nine percent, the 18 percent figure has support in the record. Its inclusion, however, would lessen one's confidence in the predicted cost figure.

F. *Proposed Disallowances, Amortizations, and Phase-in Plans*

The intervenors and the staff recommended the disallowance or deferral of River Bend capital costs on several theories: imprudence of the restart decision, imprudent construction and management of the plant, excess generating capacity, and/or protection of the economic viability of the company and its service area. The company and others have also presented plans for phasing River Bend into rate base. Satellite issues include treatment of the CEPCO buyback, of the River Bend expenses deferred pursuant to the stipulation in Docket No. 6525, and of the contra-AFUDC. The examiners have chosen to discuss those proposed adjustments in one section because the issues are intertwined and in order to allow the

Commission to compare the financial impacts of the various proposals.

1. GSU Proposals

Obviously GSU did not suggest any disallowance for imprudence. It did propose a phase-in if River Bend related expenses, however. Mr. David Beekman testified that about ten percent of River Bend 1 capital costs were included in the rates approved in Docket No. 5225. Under traditional ratemaking the remainder of River Bend capital costs would be added to rate base and be fully reflected in rates. Those, along with River Bend operating costs, depreciation, decommissioning expense, and the purchased power expense associated with the CEPCO buyback, would increase Texas retail rates by approximately $359.9 million, or 64.7 percent.

GSU's rate moderation plan, however, would defer the rate recognition of a portion of River Bend-related revenue requirements from the earliest years of operation to later years. GSU proposed to defer billing its Texas retail customers $202,900,000 of the first year's requirements, $107,800,000 of the second year's, and $49,000,000 of the third year's. The cumulative balance of those deferred revenues would be included in rate base and earn a current return. In years four through eight, GSU would recover the particular year's costs plus a specified percentage of the total cumulative deferred requirements. The proposed recovery pattern is summarized below:

Summary of Rate Moderation Plan
Texas Retail Amounts
(millions of dollars)

Year	Rate Increase	Revenue Requirement Deferrals
1	144.1	202.90
2		107.80
3		49.00
4		(8.75)
5		(60.40)
6		(98.50)
7		(89.70)
8		(102.35)

In theory at least, eight years of rate increases would not be necessary. River Bend costs would gradually decline as the CEPCO buyback decreased and as the plant accumulated depreciation. GSU did not request specific increases in this docket beyond the first year of the plan. It did request however, that the Commission's Order specify amounts of revenue deferral and the period of recovery.

In Docket No. 6525, the Commission allowed GSU to defer costs related to River Bend. The stipulation approved in that docket stated,

> The Commission hereby orders that Gulf States defer those costs (including Operating & Maintenance, insurance, fuel savings and carrying costs on Construction Work in Progress not currently included in rate base) which have been capitalized with respect to River Bend Unit 1 during its construction, as well as the buybacks of capacity (which includes capacity and operating costs from Cajun Electric Power Cooperative, Inc., including fuel savings related thereto, (hereafter referred to as "the Cajun buyback payment") effective with the commercial in-service date of this unit as defined by the

Commission; provided however, that the amount to be deferred with respect to the capacity and operating costs but excluding fuel costs of the Cajun buyback payment for the first twelve months thereof on a Texas retail basis shall not exceed the amounts actually paid to Cajun during that period or $106,557,000, whichever is smaller. Such deferrals shall also include the decommissioning costs, depreciation expense and amortization on Contra AFUDC which would otherwise be recorded on the unit and full income tax normalization to properly reflect the above items. The deferral of these costs and the accural of carrying costs thereon should continue until such time as the effective date of the rates approved in the rate case to be filed following the date on which River Bend Unit 1 is placed in-service for ratemaking purposes. The carrying costs described above shall be accrued at Gulf States' overall net AFUDC rate calculated in accordance with prescribed federal regulatory guidelines.

The recovery of all deferred costs will be included in the rate case at the time the unit is placed in-service for ratemaking purposes. However, the Commission reserves the right to exclude from rate base or other recovery any portion of the expenditures for the plant, AFUDC, capitalized expenses, capitalized depreciation, capitalized carrying costs or other capitalized costs which the Commission determines to be related to plant that is not used and useful or to have been imprudently spent or incurred. The Commission further expressly reserves the right to exclude from rate base or other recovery any portion of the deferred capacity payments resulting from the Cajun buyback which are determined to be unreasonable or unnecessary and, in such connection, the Commission reserves the right to consider whether such deferred capacity payments can and should be reduced, pro rata, for recovery purposes to the same

extent that the Commission excludes from rate base or other recovery the amounts described in the preceding sentence. Further, the parties to the rate case described above may urge any other arguments they may have regarding the inclusion or exclusion of the expenses of the Cajun buyback in cost of service. The Commission further reserves the right to consider, and all parties to the rate case described above shall have the right to raise, the reasonableness, prudence and appropriate regulatory treatment of any deferred expenses in the rate case in which rate base treatment for plant is requested.

GSU estimated its deferred costs from June 16, 1986 —the commercial operation date—through June 30, 1987. The cost over that period was $610,556,000 on a total company basis. Of course those amounts have continued to accrue beyond June. GSU proposed to amortize the deferred costs over an eight-year period and to include the unamortized balance in rate base. It requested $76,320,000 in amortization expense related to those deferred costs. GSU also proposed to amortize contra-AFUDC on a straight-line basis over the eight years. GSU included that amount as part of its depreciation expense adjustment.

2. PPC Proposals

Having concluded that the decision to build River Bend was imprudent, Mr. Komanoff proposed that GSU receive no more than it would now be paying for generation from outside sources had it cancelled River Bend in 1979. He testified that none of the River Bend investment should be allowed in rate base and that GSU should instead be allowed to recover:

(i) all expenditures GSU would reasonably have made for the purchase of equivalent energy and capacity during River Bend's lifetime, had GSU

terminated its involvement in the unit during 1979; *plus*

(ii) sunk costs in River Bend 1 through December 31, 1979, adjusted to include interest to the present; *less*

(iii) an adjustment to reflect the revenues already received by GSU through the inclusion of River Bend construction work in progress (CWIP) in ratebase.

Mr. Komanoff derived the first element of this proposal by calculating the rate which GSU would now have to pay qualifying facilities for the amount of power produced by River Bend. In total under his recommendation, GSU would receive approximately $1.878 billion in future recovery, on the basis of:

(i) a QF entitlement of $1.850 billion, *plus*

(ii) $415 million for 1979 sunk cost recovery, *plus*

(iii) $41 million for 1985-86 generation, *less*

(iv) $427 million already received through CWIP in ratebase.

According to Mr. Komanoff, that amount is approximately one-third of what GSU would receive if its entire River Bend investment were placed in rate base.

3. OPC Proposals

Dr. Andersen believed that GSU should have replaced River Bend with coal-fired capacity. He therefore compared the actual cost of River Bend to the cost of an equivalent amount of coal-fired generation. Dr. Andersen concluded that $1.4 billion of GSU's share of River Bend should be disallowed.

The Coalition endorsed Dr. Andersen's recommendation. GSU witness Marshall also endorsed the concept underlying it:

> The penalty should be determined by comparing the cost that would result from a prudent management process to the costs that resulted from the imprudent management process.

GSU Ex. 35 (Marshall direct test.) at 3.

Dr. Marshall, of course, believed that GSU had been prudent in restarting River Bend, so that any penalty would be inappropriate. He did not analyze Dr. Andersen's numbers.

Dr. Andersen also identified, but did not recommend, two alternative approaches. The first, based upon the economic efficiency of River Bend, would disallow all costs in excess of $900 to $1240 million. The second would mitigate the $1.4 billion recommended disallowance by placing more of a burden on ratepayers. Since he considered GSU's actions to have been imprudent, he did not recommend that "risk-sharing" plan, under which $902 million of GSU's investment would be disallowed. Dr. Andersen reached that figure by splitting in half his economic-efficiency-based $1.804 billion "excess" cost.

In addition to his imprudence disallowance, Dr. Andersen proposed a phase-in based on excess generating capacity. He recommended that costs associated with 1258 MW, or 18.3 percent of the generating capability owned by GSU, be held in inventory until required to serve load. By "held in inventory", he meant that recovery of return, depreciation, and income taxes be deferred. That proposal would decrease GSU's Texas rate base by $180.479 million. Dr. Andersen derived that figure by subtracting his proposed imprudence disallowance and accumulated depreciation from Texas gross plant and applying the 18.3 percent to the remainder. He proposed that GSU be allowed to earn a capitalized return on those

deferred costs and that the accumulated deferrals be amortized over a 25-year period beginning in 1991. The inventoried MW would be placed in rate base incrementally, as needed.

Dr. Andersen testified that the CEPCO contract was a bad contract when signed and that its impact is even worse today, considering GSU's excess capacity. In conjunction with his imprudence disallowance Dr. Andersen recommended that 46 percent of the CEPCO capacity payments be disallowed. He recommended that the remaining 54 percent be capitalized and amortized over the remaining life of the plant. In effect, the 54 percent would be treated as long-term financing associated with construction of River Bend. That adjustment would reduce Texas jurisdictional expense by $53.748 million and add $14.512 million to current rate base. With corresponding adjustments to return, taxes, and amortization expense, the net impact on Texas jurisdictional revenue requirement would be a $50.884 million reduction.

Dr. Andersen also proposed a 46 percent disallowance of deferred River Bend costs associated with return, depreciation, and CEPCO capacity payments. He recommended the following treatment of deferred costs not disallowed:

1. CEPCO capacity payments and River Bend depreciation expense should be amortized over the remaining useful life of River Bend with inclusion of the unamortized balance in rate base.

2. Deferred O&M expense net of fuel savings, deferred return and deferred decommissioning expense should be amortized over the eight year period requested by GSU, but the unamortized balance should be excluded from rate base.

According to OPC, the eight-year amortization would allow GSU to recover 64 percent of the present value of those costs. Dr. Andersen believed partial recovery to

be reasonable given the lack of benefits to ratepayers from those expenses. Dr. Andersen's deferred cost recommendations would reduce the Texas jurisdictional revenue requirement by $38.981 million. He recommended that costs booked after June 30, 1987, receive similar treatment but that recovery be deferred until GSU's next rate case.

Dr. Andersen also recommended accelerated amortization of contra-AFUDC to reduce the rate impact of River Bend during its early years of operation. He recommended that the amortization period be reduced to seven years and that the amounts amortized be proportional to River Bend-related excess capacity. That proposal would reduce Texas revenue requirements by $20 million relative to a traditional case.

OPC also offered two alternative construction-based disallowances if the restart decision is not found imprudent. One alternative, based on Mr. Komanoff's statistical analysis, would disallow $940 million as unexplained costs. The other would be to disallow 70 percent (GSU's share) of the $639.5 million found imprudent by PPC witnesses. That figure included $500 million related to Mark III costs, $64.5 million associated with TDI problems, and $75 million associated with the 50-month schedule.

4. Cities Proposals

Cities' witnesses Daniel Lawton and Jacob Pous recommended a disallowance based upon a minimum of 800 MW of capacity on GSU's system in excess of its peak load plus a 30 percent reserve margin. Mr. Lawton used a 30 percent reserve margin instead of the 18 percent required by the Southwest Power Pool (SPP) as a risk-sharing mechanism and in recognition of the fact that generation is added in discrete units which cannot precisely match reserve requirements. Mr. Lawton calculated GSU's reserve margin by comparing GSU's projected net peak load to its available resources, as set forth

on the company's most recent generation plan. The reported available resources included River Bend and the Cajun buyback but not the capacity purchased from the Southern Companies or 443 MW of gas-fired generation which the company has placed in cold storage. Mr. Lawton reincluded that 443 MW, then averaged the reserve levels for 1986-1988 in order to recognize both test year and rate year levels. His reserve calculation is shown below:

Year	Peak	System Resources	Percent Reserves	Excess MWs
1986	5006	7483	49.5%	975
1987	4947	7169	44.9%	738
1988	4942	7105	43.8%	680
Average	4965	7252	46.1%	798

Mr. Pous first discussed recent changes in the generating capacity available to GSU. Those changes were the addition of 658 MW of GSU-owned River Bend generation and 197 MW bought back from Cajun, and the subtraction of the units placed in cold storage (443 MW), the transfer of Nelson Unit 7 (90 MW) of the Louisiana Steam Station, and the proposed transfer of Nelson Units 1 and 2 (200 MW) to a joint venture. Those changes resulted in a net increase of 132 MW. Before those changes GSU's net cost of plant in service was $179 per kW; with the various changes that cost is $745 per kW.

Mr. Pous discussed two methods of pricing the 800 MW of excess capacity identified by Mr. Lawton. The first would be not to allow a return on 800 MW associated with the last increment of capacity to come on-line (River Bend, including the Cajun buyback) but to allow depreciation and O&M expense. The resulting rate base disallowance would be $3,632,800,000 ($4,541/kW x 800).[9] The second alternative would be to price the

[9] *See* Cities Ex. 10 at 75-76 and Tr. Vol. 73 at 11209-10 for a further explanation of Mr. Pous' calculation.

excess capacity on the basis of the system average cost. That average cost is $693/kW if the stored and transferred units are included; GSU's overall rate base would therefore be reduced by $554.4 million ($693/kW x 800).[10] Mr. Pous would not allow the recovery of depreciation and non-fuel O&M on that amount, as the ratepayers have already paid such expenses on the average plant.

Recognizing the company's financial situation, Mr. Pous proposed adoption of the second alternative, which would decrease revenue requirements by approximately $96 million on a total electric basis and $39 million on a Texas retail basis. Mr. Pous would allow GSU to reduce the amount of excess capacity disallowance in later rate proceedings, as its capacity reserve situation improves, and would retain for ratepayers the option of switching to the first alernative pricing mechanism at some future time.

Although Mr. Lawton did contend that GSU's decision to restart River Bend was imprudent, he acknowledged that his excess capacity analysis was based upon the end result of GSU's planning. Tr. Vol. 60 at 10691-93, 10696.

Mr. Lawton proposed several adjustments to the River Bend-related revenue requirements which were deferred pursuant to the Commission's order in Docket No. 6525. He recommended excluding from the deferral account any carrying costs on cash outlays. He considered those amounts to be outside the stipulation. That adjustment removed $5,256,000 and $12,123,000 from Texas retail and total company expenses respectively.

Mr. Lawton also proposed that the level of River Bend deferred costs be reduced by excess deferred taxes currently held by GSU and that the remaining deferred costs be recovered over the life of River Bend. The first

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[10] *See* Cities Ex. 10 at Ex. JP-13 for an explanation of the cost per kW calculation.

adjustment referred to the fact that GSU has in the past collected deferred taxes under the assumption that it would have to pay those losses at a 46 percent rate. The rate is now 34 percent. Mr. Lawton recommended that the difference between those rates, which he estimated to be $142 million on a total electric basis, be used to offset the deferred revenue requirements accrued pursuant to Docket No. 6525.

Mr. Lawton further proposed that the remaining deferred costs be amortized over the life of the plant. That treatment would recognize that the deferred accounting treatment is an extraordinary form of rate relief. Mr. Lawton pointed out that FERC had denied any recognition of those costs for GSU.

Mr. Lawton also recommended that the deferred expenses be adjusted by $1.50 for every dollar of interim rate relief it has received. That adjustment is consistent with the Commission's interim rate order.

The Cities did not recommend a specific phase-in plan. Mr. Pous suggested, however, that the first-year increase be no more than $115 million.

5. TIEC Proposals

Jeffrey Pollock on behalf of TIEC also advocated a separate "used and useful" standard divorced from prudence. As he phrased it,

> The "prudence" test focuses on the *procedures* involved—that is, did management make the correct decisions and operate as it should have. The "used and useful" test, on the other hand, focuses on the *results*.

Pollock test. at 8.

Mr. Pollock took issue with the projected reserve margins of 33, 29, and 25 percent for 1987-1989 calculated by GSU in Schedule L-1, page 6 of its rate filing package.

He testified that GSU had overstated its projected peak demand by including 252-303.1 MW of interruptible load and that GSU had understated its resources by excluding the 443 MW of mothballed capacity and, perhaps, the 200 MW capacity of Nelson 1 and 2 transferred to the Nelson Industrial Steam Company. He removed the interruptible load because GSU does not plan new capacity to serve such loads and because other utilities (e.g. HL&P and CP&L) do not include interruptible load in calculating their projected reserve margins.[11] Mr. Pollock concluded that if interruptible load is considered, not all of River Bend's capacity will be needed until 1991 to meet an 18 percent reserve margin. Excluding interruptible load, the entire plant would not be needed until 1996 and no part of it would be needed until 1990. He stated that none of the Cajun buyback capacity is needed and that his analysis would justify the deferral of River Bend capacity-related costs for four to eight years.

Dr. Gail Heyne Hafer presented sample phase-in plans on TIEC's behalf. She did not recommend any particular plan, as adoption of a particular plan would depend upon the resolution of prudence and other revenue requirement issues.

Dr. Hafer observed that under GSU's rate moderation plan the proposed first year increase in base rates would be 44.3 percent. For that reason, and to move closely match capacity needs with River Bend-related rate increases, she presented an alternative plan using 4 years of deferrals and 10 years of recovery, and another using 5 years of deferrals and 15 of recoveries. These plans assumed no disallowance of River Bend costs. The first produced a 32.6 percent revenue increase in the first year, the second a 30.6 percent increase. She also examined scenarios involving a $1.4 billion disallowance

[11] Mr. Lawton's calculations for the Cities were based on GSU's net peak load estimates and therefore included the interruptible load which Mr. Pollock disputed.

and a $500 million disallowance. In addition she examined the effects of extending amortization of the accounting deferrals to 15 years, of removing the Cajun buyback capacity payments, and of reducing the overall rate of return to 11.48 percent.

6. North Star Proposals

North Star's proposal, which was premised on the language of PURA Sections 39 and 41, focused on the economic consequences of including River Bend in rate base. North Star witnesses Samuel Hadaway and Brent Heidebrecht did not study the prudence of River Bend but instead analyzed the effects of higher rates on the company's load and its ability to compete for wholesale customers. According to Dr. Hadaway,

> Even if GSU were granted the opportunity to raise rates as it has requested, it is highly unlikely that the projected revenues would be forthcoming. Most likely GSU's rate proposal would drive additional customers off the system, and the Company's "death spiral" would be assured.

On the other hand, he pointed out, a large direct disallowance might drive GSU into bankruptcy.

North Star proposed that 20-40 percent of River Bend be transferred to shareholders either "below the line" or to a shareholder-owned affiliate. Mr. Heidebrecht presented rate moderation models which incorporated alternative transfers of 20-40 percent and a ten-year phase-in of the remaining investment. North Star recommended that a transfer of 30 percent, the midpoint of its range, be approved. The 30 percent figure represented a reduction of about $1,387 per kW in River Bend's regulatory value ($912 million on a total company basis). That portion would be available for off-system sales which, if achieved, would benefit GSU's shareholders directly. Dr. Hadaway also recommended a 30 percent reduction to

the deferred return and depreciation portions of the expenses deferred pursuant to Docket No. 6525.

In support of North Star's proposal, Dr. Hadaway cited innovative plans agreed to by El Paso Electric Company (EPEC) in New Mexico and Commonwealth Edison in Illinois. In New Mexico, EPEC agreed to transfer its interest in Palo Verde 3 to an unregulated subsidiary. Commonwealth Edison filed a similar proposal in Illinois with regard to its Byron II and Braidwood I and II nuclear plants. Commonwealth Edison's proposal was rejected by the Illinois Commerce Commission, however.

The 30 percent dereguation approach would yield a first-year Texas base rate increase of $88.4 million (including accounting and tax adjustments recommended by North Star accounting witness Ellen Blumenthal).

Dr. Hadaway compared GSU's financial indicators to the industry median as of September 30, 1986:

	GSU	Industry Median
Interest Coverage *	1.9/1.1	3.4/2.9
Long-term Debt %	54%	47%
AFC % of Earnings	120%	24%
Internally Generated Cash	$0	$88 million
Cash Construction	$157 million	$142 million
Internal Cash Generation	0%	91%

* including/excluding AFUDC

They did not look good. Dr. Hadaway believed that GSU's proposal would attempt to raise those indicators too fast. By 1990 its internally generated cash would be at an annual rate of $918 million; annual net cash flow would be 18 percent of total permanent capital; debt leverage would decline to 36 percent; and the SEC interest coverage ratio (excluding AFUDC) would climb to 3.99 times. According to Dr. Hadaway, GSU's internally generated cash would be 10 times the industry median and its debt leverage the lowest of any major electric utility in the United States. Dr. Hadaway char-

acterized those lofty goals as "patently unreasonable," particularly in light of the possibility that unnecessarily high rates would drive customers off the system.

Dr. Hadaway asserted that within the 20 to 40 percent range of base rate reductions GSU's retained earnings would not be eliminated nor its capital impaired. As an example he used Commonwealth Edison. The Commonwealth Edison plan would have transferred the Byron II and Braidwood I and II units to a wholly-owned subsidiary subject to regulation by FERC. The plants would no longer have been subject to Statement of Financial Accounting Standards (SFAS) 71 (regulatory accrual of equity AFUDC), but to SFAS 34 (allowed unregulated capitalized interest during construction). About 25 percent of the AFUDC on the plants ($550 million out of $2200 million) would have been written off. GSU's total AFUDC on River Bend was $981 million as of June 16, 1986. Thirty percent deregulation would subject $294 million to the SFAS 71/SFAS 34 accounting adjustment. Dr. Hadaway suggested that GSU's probable total company write-off under his plan would be about 25 percent of that amount, or $74 million.

Mr. Heidebrecht's proposed ten-year phase-in plans contemplated base rate increases in some years and small decreases in others. He recommended overall rate increase of various amounts each of the ten years. His contemplated pattern of deferrals and amortizations was fairly stable.

7. Staff Proposals

Dr. Pflaum recommended a disallowance of $461.3 million for the alleged imprudence of the restart decision. He based that on the difference of 15.15 percent between the mid-point of Mr. Hadzi-Pavlovic's recommended Definitive Cost Estimate range ($1.90 billion) and his own point of $1.65 billion, derived from his busbar study, at which the potential problems with River Bend would

have been "swept aside" by its perceived economic advantages. That percentage of GSU's total $3.045 billion share of River Bend equals $461.3 million. Dr. Pflaum recommended exclusion of that amount on the theory that the penalty should fit the crime—that GSU's imprudence was not so obvious or its actions so unwarranted that a disallowance of the size recommended by Dr. Andersen would be appropriate. Dr. Pflaum's proposal reflected his view that the economics of the decision were marginal as well as his "personal feelings" as to what level of River Bend cost projection would have led him to change his recommendation.

GSU claimed that Dr. Pflaum's recommended disallowance should be reduced to $261 million to reflect errors in his calculation of deferred taxes in his busbar study. That assertion is supported by the record. Dr. Pflaum admitted that correction of his error would shift his calculations by $114 million in favor of nuclear generation. Tr. Vol. 107 at 16726-45, 16847-49, 16892. That upward shift would change to 8.57 percent the ratio between $1.90 billion and the point at which Dr. Pflaum believed financial indicators would clearly have favored River Bend. That percentage, applied to GSU's share of River Bend, would yield a disallowance of approximately $261.0 million.

As has been mentioned in the "Construction" section of this report, Dr. Pflaum also recommended that 33 percent of GSU's investment in River Bend be held in abeyance until the company could provide a better explanation of plant costs. Mr. Hadzi-Pavlovic also proposed disallowance of $10.5 million in TDI costs to encourage GSU to pursue legal remedies against TDI.

Mr. Paul Bellon presented the staff's proposed treatment of deferred expenses. He presented those adjustments in the "Amortization" portion of his revenue requirement schedule. GSU requested that $76,320,000 of

deferred expenses be included as amortization expense—a figure it reached by amortizing total estimated deferred costs of $610,556,000 over eight years. Mr. Bellon calculated total deferred costs of $426,778,531. He reached that total by including only actual cash outlays through January 1987, the last month for which he had actual figures, and calculating return on those amounts, plus depreciation, decommissioning costs, and return on River Bend investment through June 1987. He then reduced deferred depreciation and return on investment to conform with Dr. Pflaum's disallowance recommendation. Mr. Bellon proposed that actual cash outlays after January 1987, and return after June 1987, simply be placed in rate base in GSU's next rate proceeding. The 1.5 times interim revenue offset would be calculated against those amounts at that time.

Mr. Bellon recommended that contra-AFUDC be amortized over 10 years to conform with the staff's rate moderation plan. He included contra-AFUDC as a $23,353,376 reduction to amortization expense.

Mr. Reilley presented the rate moderation plan. He offered two alternatives: four years of deferrals (with rate increases) and six of amortization (with flat rates), or five years of deferrals and five of amortization. He pointed out that the 5/10 plan would yield more gradual rate increases but would cost more overall, because the deferrals would be placed in rate base and earn a full return. Mr. Reilley advocated a ten-year phase-in period rather than a longer one partly because of GSU's financial condition and partly because of the FASB requirements that deferrals be recovered within 10 years or be written off for reporting purposes. Although he expressed frustration over the notion of FASB dictating regulatory policy, he believed it unwise to threaten GSU's financial integrity by extending recovery beyond the 10 years.

8. GSU Rebuttal Case

GSU vehemently objected to any deviation from the prudence standard as contemplated by the proposals advanced by the Cities, TIEC and North Star. It presented testimony that reliance on a results-based criterion would violate the "regulatory bargain" under which a utility is granted a monopoly franchise in return for the obligation to serve all customers and to provide adequate service and facilities. Under that bargain, utility shareholders are allowed only a limited return on successful investments but are protected from losses on prudent investments which turn out to be unsuccessful. According to GSU, the term "used and useful", which has been used in Texas utility regulation statutes since at least 1937, must be interpreted in light of the regulatory bargain and traditional ratemaking practices. Such an interpretation is also consistent with the constitutional prohibition against the taking of property without just compensation. *See Missouri ex rel. Southwestern Bell Tele. Co. v. Public Service Commission*, 262 U.S. 276, 289, n.1; 43 S.Ct. 544, 547 (1923) (Brandels, J., concurring).

GSU contended that a results-based standard would discourage utilities from making long-range investments. It also pointed out that the Texas Commission has recognized that even technically unused property may be accorded rate base treatment if the investment is prudent and if the company has specific plans for the property within approximately a ten-year period. GSU further argued that North Star's recommendation had no basis whatsoever in the law. Dr. Hadaway admitted, on cross-examination, that he had not attempted to determine whether his approach had any legal foundation. Tr. at 9320-22.

GSU claimed that River Bend is used and useful in any event, even if the prudence standard were abandoned. It called attention to the plant's low fuel cost. One of its witnesses, Edward Loggins, specifically chal-

lenged TIEC's deduction of 252-303 MW of interruptible load from peak load forecasts. He stated that 83 MW taken by North Star was the only load that GSU could confidently predict would be present and interruptible at the system peak, based upon customer-specific assessments. He disagreed with TIEC's, the Cities', and OPC's argument that the units in cold storage should be treated as current resources. Mr. Loggins also testified that GSU's "excess" capacity was useful in providing flexibility and fuel diversity. Another witness, Darrell A. Smith, stated that a reserve margin as high as 40 percent is a reasonable consequence of the long-term planning of new units to meet an 18 percent reserve target.

Obviously the company disagreed with any disallowance based on the imprudence of the restart decision or mismanagement of construction. It also disputed the manner in which the parties calculated their proposed disallowances. In summarizing the testimony the examiners have already discussed the problems GSU perceived with Dr. Andersen's nuclear/coal comparison, Mr. Komanoff's statistical analysis, MHB's calculation of construction imprudence, and Dr. Pflaum's busbar study and regression analysis as well as his proposal to leave 33 percent of River Bend costs in abeyance. GSU also pointed out that Mr. Komanoff's QF/Cancel disallowance methodology ignored the fact that the company would have needed to build some type of capacity if it had cancelled River Bend.

Mr. McBride and Mr. Donnelly investigated the potential effects of the various disallowance proposals on GSU's financial condition. They identified two key criteria:

1. Pre-tax interest coverage excluding AFUDC and deferrals; and

2. Cash flow as a percent of permanent capital.

Mr. McBride presented tables which compared the effects of the parties' proposals on those criteria using GSU's forecasting assumptions. Those tables are included as pages 157A and 157B [App. 194a-197a].

Mr. McBride and Mr. Donnelly both stated that short-term achievement of pre-tax interest coverage of about 1.3 times was necessary to allow GSU to finance on reasonable and competitive terms in the capital markets. Mr. McBride testified that only GSU's plan would meet that criterion.

Mr. McBride and Mr. Donnelly also testified that a critical test of the long-term acceptability of rate moderation plans was the length of time required to achieve technical mortgage bond issuance capacity. The criterion for that ability is that earnings available for interest coverage be 2.0x proforma mortgage interest. Those earnings can include no more than 15 percent of "other income" such as AFUDC and deferrals. In other words, 85 percent of the earnings must be actual revenues. Mr. McBride therefore used as a benchmark 1.7 times pre-tax interest coverage (excluding AFUDC and deferrals) to calculate when the various proposals would enable GSU to meet that milestone. Assuming rates in effect at the end of June 1987, Mr. McBride calculated that

GULF STATES UTILITIES COMPANY ANALYSIS OF FINANCIAL CRITERIA
PRE-TAX INTEREST COVERAGE EXCLUDING AFDUC AND DEFERRALS

Party	Plan Life	Write Off	GSU Computed Financial Criteria (12 Months Ended)								
			1987	(1) 6/30/88	1988	(2) 6/30/89	1989	6/30/90	1990	6/30/91	1991
GSU	3-8	—	.69x	1.30x	1.90x	2.41x	2.91x	3.53x	4.14x	4.38x	4.62x
TIEC	4-14	—	.43x	.85x	1.27x	1.73x	2.18x	2.49x	2.80x	2.81x	2.81x
TIEC	5-20	—	.41x	.78x	1.14x	1.54x	1.93x	2.29x	2.65x	2.75x	2.84x
TIEC	4-12	.5B	.43x	.84x	1.25x	1.69x	2.13x	2.43x	2.73x	2.76x	2.78x
TIEC	5-17	.5B	.34x	.66x	.98x	1.36x	1.73x	2.09x	2.44x	2.60x	2.75x
TIEC	3-11	1.4B	.46x	.85x	1.24x	1.56x	1.88x	2.13x	2.37x	2.52x	2.66x
TIEC	4-14	1.4B	.30x	.58x	.86x	1.16x	1.46x	1.74x	2.01x	2.27x	2.52x
Staff (3)	4-10	.6B	.43x	.76x	1.09x	1.42x	1.75x	2.08x	2.40x	2.58x	2.76x
Staff (3)	5-10	.6B	.43x	.74x	1.04x	1.31x	1.57x	1.86x	2.14x	2.41x	2.68x
NSST	4-10	.6B	.46x	.82x	1.18x	1.40x	1.61x	1.73x	1.84x	2.06x	2.28x
NSST	4-10	.9B	.37x	.67x	.98x	1.16x	1.34x	1.43x	1.52x	1.74x	1.96x
NSST	4-10	1.2B	.27x	.52x	.77x	.94x	1.10x	1.17x	1.23x	1.42x	1.60x
Certain Cities	N/S	1.4B	.51x	.77x	1.02x	1.09x	1.16x	1.24x	1.31x	1.38x	1.45x

Certain Cities	N/S	1.4B	.41x	.61x	.80x	.86x	.91x	.96x	1.00x	1.04x	1.08x
OPUC	4-29	1.4B	.28x	.41x	.54x	.58x	.62x	.65x	.68x	.70x	.72x
OPUC	7-10	1.4B	.28x	.41x	.54x	.58x	62x	.65x	.68x	.70x	.72x

N/S None Stated.

(1) See related discussion in Mr. McBride's testimony. The achievement of pre-tax interest coverage of about 1.3x within the first year of the rate moderation plan provides an indication of financial stability which will lead to greater accessibility of capital markets.

(2) See related discussion in Mr. McBride's testimony. The achievement of pre-tax interest coverage above 1.7x serves as a proxy for first mortgage bond issuance capacity under the mortgage indenture. Such achievement should allow for financial flexibility in accessing capital markets which should prove economical to both ratepayers and the Company.

Changes from Rebuttal Testimony, Phase III, are underlined.

Exhibit —— (CWM-1)
(Response to Staff Suppl.)
1986 Texas
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(Revised)

GULF STATES UTILITIES COMPANY
ANALYSIS OF FINANCIAL CRITERIA
CASH FLOW AS A % OF PERMANENT CAPITAL

Party	Plan Life	Write Off	GSU Computed Financial Criteria (12 Months Ended)								
			1987	6/30/88	1988	6/30/89	1989	6/30/90	1990	6/30/91	1991
GSU	3-8	—	.78 %	3.99 %	7.20 %	9.63 %	12.06 %	14.52 %	16.98 %	17.42 %	17.86 %
TIEC	4-14	—	(.14) %	2.05 %	4.24 %	6.66 %	9.07 %	11.40 %	13.72 %	14.96 %	16.19 %
TIEC	5-20	—	(.30) %	1.61 %	3.51 %	5.57 %	7.62 %	9.48 %	11.33 %	12.54 %	13.75 %
TIEC	4-12	.5B	(.28) %	1.95 %	4.18 %	6.61 %	9.04 %	11.10 %	13.16 %	14.03 %	14.90 %
TIEC	5-17	.5B	(.85) %	.85 %	2.55 %	4.65 %	6.74 %	8.56 %	10.38 %	11.66 %	12.94 %
TIEC	3-11	1.4B	(.30) %	2.02 %	4.33 %	6.36 %	8.38 %	9.87 %	11.36 %	11.74 %	12.12 %
TIEC	4-14	1.4B	(1.43) %	.14 %	1.71 %	3.69 %	5.66 %	7.24 %	8.82 %	9.97 %	11.12 %
Staff (1)	4-10	.6B	(.39) %	1.42 %	3.22 %	5.01 %	6.79 %	8.35 %	9.91 %	10.66 %	11.41 %
Staff (1)	5-10	.6B	(.39) %	1.26 %	2.91 %	4.34 %	5.77 %	7.11 %	8.45 %	9.64 %	10.83 %
NSST	4-10	.6B	(.18) %	1.78 %	3.73 %	4.88 %	6.03 %	6.43 %	6.82 %	7.68 %	8.53 %
NSST	4-10	.9B	(.94) %	.73 %	2.39 %	3.54 %	4.68 %	5.10 %	5.51 %	6.47 %	7.43 %
NSST	4-10	1.2B	(1.77) %	(.42) %	.94 %	2.08 %	3.21 %	3.57 %	3.93 %	4.93 %	5.92 %

Certain Cities	N/S	1.4B	.02 %	1.42 %	2.82 %	3.26 %	3.69 %	4.09 %	4.48 %	4.75 %	5.02 %
Certain Cities	N/S	1.4B	(.70)%	.30 %	1.30 %	1.64 %	1.97 %	2.26 %	2.54 %	2.72 %	2.90 %
OPUC	4-29	1.4B	(1.87)%	(1.36)%	(.85)%	(.58)%	(.31)%	(.11)%	.09 %	.21 %	.33 %
OPUC	7-10	1.4B	(1.87)%	(1.36)%	(.85)%	(.58)%	(.31)%	(.11)%	.09 %	.21 %	.33 %

N/S None Stated.

(1) Changes from Rebuttal Testimony, Phase III, are underlined.

the proposals would meet that long-term criterion at the following times:

Party	Scenario	Earliest Date For Mortgage Issuance
GSU	3 Step, 8 Year Plan	2nd Half 1988
TIEC	4 Step, 14 Year Plan (Without Disallowance)	1st Half 1989
TIEC	4 Step, 14 Year Plan (With $1.4 Billion Disallowance)	1st Half 1990
Staff	4 Step, 10 Year Plan (With or Without Disallowance)	2nd Half 1989
	5 Step, 10 Year Plan (Without Disallowance)	2nd Half 1989
	5 Step, 10 Year Plan (With Disallowance)	1st Half 1990
North Star	20% "Below The Line" Plan	1st Half 1990
	30% "Below The Line" Plan	1st Half 1991
	40% "Below The Line" Plan	after 1991

He testified that the Cities' and OPC's proposals would not allow mortgage issuance capacity until at least after 1991, if ever. In evaluating the Cities' proposal he apparently considered only the maximum $115 million first-year increase recommended by Mr. Pous. The Cities did not present a plan for future increases.

On cross-examination, Mr. McBride admitted that if North Star's revenue and financing assumptions are correct North Star's 30 percent plan would allow mortgage bond issuance in 1988. North Star Exs. 21-25; Cities Exs. 37-39; Tr. Vol. 95 at 14822-31, 14852-66. He also conceded that depreciation, a non-cash expense, was included in the company's net income and interest coverage calculations. Id. at 14888-90. He further agreed that if one ignored Dr. Andersen's recommendation concerning the CEPCO buyback, OPC's recommendation

would yield results similar to North Star's and the Cities' during the first year. Dr. Andersen would recommend no increases beyond the first year, however. Tr. Vol. 96 at 14960-61.

Mr. McBride's analysis of the first-year base rate increases which would arise from the parties' proposals is summarized below:

	Plan Life	Years of Deferral	Years of Recovery	1st Year Increase (in millions)
GSU	8	3	5	144
Staff	10	4	6	102
Staff	10	5	5	102
North Star	10	4	6	115
North Star	10	4	6	88
North Star	10	4	6	62
TIEC	14	4	10	109
TIEC	20	5	15	102
TIEC	12	4	8	103
TIEC	17	5	12	81
TIEC	11	3	8	104
TIEC	14	4	10	64
Cities	—	—	—	115
Cities	—	—	—	90
OPC	29	4	25	63
OPC	10	7	3	63

GSU's proposed increase, properly calculated, is $153 million, not $144 million.

Under the staff's rate moderation plan without disallowance, the first year increases would still have been approximately $100 million. The apparent anomaly between that and its disallowance proposal is explained by the fact that Mr. Reilley's first-year recommendations were driven largely by financial considerations. Thus under the disallowance proposals the deferred revenues would be lower, but not the first year revenue requirement.

Mr. Donnelly specifically addressed the OPC, North Star, and staff proposals. He believed Dr. Andersen's recommendation would leave GSU in a "hopeless" situation. He believed that North Star's proposal offered supportive criteria in its later years, but not its early ones, which he characterized as "make or break" years for GSU. The staff's proposal, without any disallowance, also offered inadequate early relief, while its large deferrals would be viewed as "suspect" by the financial community. The staff disallowance case, with a first-year interest coverage of 0.6 times, he viewed even less favorably. He took Mr. Reilley to task for presenting Public Service of New Hampshire (PSNH) as a company which had been able to finance with a coverage of less than 1.0 times. He did not regard PSNH as a desirable role model for GSU. Mr. Reilley explicitly stated that coverage below 1.0 times was untenable in the long-term, however, and mentioned PSNH only in passing.

Mr. Donnelly testified that in the event of a resurgence of growth requiring new transmission capability,

> [GSU] would be, even under the Rate Moderation Plan, flying very dangerously with perhaps a wing and a half, and we would be unable, perhaps, to meet the bumps in the road that we may encounter because of our limited availability [sic] to access the capital market. . . .[12]

Tr. Vol. 26 at 4077 (Donnelly cross).

In other words, Mr. Donnelly believed that even GSU's rate moderation plan left the company skating on thin ice.

Dr. Olson and Mr. Osbon testified as to the potential effects of the proposed disallowances on the financial community. Dr. Osbon took issue with a statement by Dr.

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[12] The Commission should not infer that the urbane Mr. Donnelly habitually speaks in mixed metaphors.

Andersen that his "risk-sharing" $902 million write-off proposal would support a market price of $10.00 per share for GSU's stock. He agreed with Mr. McBride that the Cities, PPC, and OPC proposals would not provide a first year revenue level adequate for access to capital markets on reasonable terms. Mr. Osbon testified that although the financial community expected a phase-in of River Bend's costs, it would be skeptical of a plan heavily weighted toward future recoveries. In the short term, it was important to achieve a one-to-one relationship between expenses and cash flow. He stated that the Commission's objectives in setting rates must be: (1) to prevent significant loss of sales; (2) to enable GSU to avoid bankruptcy; (3) to provide for a long-term, but relatively rapid restoration of financial health; and (4) to enable GSU to refund its high interest bonds.

Mr. Willis testified on the subjects of deferred costs, SFAS 92 requirements for phase-in plans, and the financial and accounting effects of various proposals. Mr. Willis proposed that the offset of deferred costs by 1.5 times interim revenues be itself offset by deferred tax expense. He recommended that deferred expenses be reduced by $0.90 instead of $1.50 for each $1.00 of interim revenues collected. Both the Cities and North Star disagreed with that proposal.

Mr. Willis argued that Mr. Bellon's postponement of some of GSU's deferred River Bend costs was inappropriate. He recommended use of "the latest data" made available during the hearing. He also testified that if new rates were not effective by January 1, 1988, the equity portion of the return accrued after that date could not be recognized for financial reporting purposes until actually included in rate base. That amount would equal about $20 million between January 1 and February 1, 1988.

Mr. Willis argued against the amortization periods for deferred costs proposed by Mr. Lawton and Dr. Ander-

sen. He first argued that periods longer than 10 years would not meet contemplated FASB requirements. The final version of SFAS 92, however, which was published during the hearing, did not prohibit such treatment of costs deferred before the effective date of the order implementing a phase-in plan. Mr. Willis also argued that an amortization period longer than ten years was inappropriate given GSU's financial condition.

Mr. Willis did not believe that North Star's 20-40 percent deregulation proposal would avoid a substantial write-off. Since recovery was by no means assured, an asset impairment test could require such a write-off.

Mr. Willis summarized the four criteria which, under SFAS 92, a phase-in plan must meet to avoid a write-off of the deferred revenues. SFAS 92 states,

The criteria to determine whether capitalization is appropriate are:

a. The allowable costs in question are deferred pursuant to a formal plan that has been agreed to by the regulator.

b. The plan specifies the timing of recovery of all allowable costs that will be deferred under the plan.

c. All allowable costs deferred under the plan are scheduled for recovery within 10 years of the date when deferrals begin.

d. The percentage increase in rates scheduled under the plan for each future year is no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year. That is, the scheduled percentage increase in year two is no greater than the percentage increase granted in year one, the scheduled percentage increase in year three is no greater than the scheduled percentage increase in year two, and so forth.

All four criteria must be met. Mr. Willis testified that all the proposals except the company's and the staff's failed to meet at least one of them. North Star's plan violated criterion (d). In its brief North Star countered that Mr. Willis had considered only base rates, not the pattern of overall increases contemplated by Mr. Heidebrecht's phase-in plans. The overall increases appear to violate that criterion as well, however. Mr. Willis also proposed language for the Commission's Order designed to satisfy SFAS 92.

Mr. Beekman opposed Mr. Lawton's proposed reduction of deferred accounting expenses by the amount of "excess" deferred taxes accumulated by GSU. Mr. Beekman also argued that North Star's proposal would require a significant write-off and that it lacked certain provisions present in the El Paso and Commonwealth Edison plans to protect the value of the transferred asset. In *El Paso*, a specific provision was included to amortize to cost of service the difference between the AFUDC recorded under SFAS No. 71 and the interest capitalized under SFAS 34. Dr. Hadaway's proposal contained no such provision. The Commonwealth Edison proposal would have obligated the utility to make a fixed monthly payment for the right to purchase power and energy from the nonregulated utility. The value of the asset would thus have been protected. North Star's plan had no such provision.

Mr. Beekman also criticized the manner in which the parties other than the staff amortized the River Bend revenue requirements deferred under their rate moderation proposals. The staff and the company adjusted those deferrals to produce target price patterns, a procedure which Mr. Beekman regarded as preferable. According to Mr. Beekman, only that methodology avoided erratic patterns of rate increases and decreases.

In supplemental rebuttal, Mr. Beekman identified a discontinuity between Mr. Reilley's computations and Ms.

Somlak Miphan's proposed rate design. Mr. Reilley did his computations on a system-wide basis, while Ms. Miphan allocated the revenue requirement deferrals and associated deferred taxes to the Texas retail jurisdiction using the company's specific assignment factors.

Finally, Mr. Beekman proposed that the Commission approve a "true-up" mechanism for River Bend non-fuel costs under a rate moderation plan. The true-up would cover two components: (1) the difference between estimated non-fuel O&M expenses and actual expenses incurred and (2) post-completion capital additions to River Bend. Under Mr. Beekman's proposal the company would file, in the second quarter of a specific year of the rate moderation plan, (1) actual results from the immediately preceding River Bend rate year; (2) estimated results for the then-current River Bend rate year; and (3) estimated costs for the River Bend rate year to come. GSU would propose revised rate and deferral patterns. After hearings, the Commission would set new rates within six months, in time for the new rate year. Any rate changes based upon non-River Bend items would have to come through regular rate proceedings. Otherwise they would not be considered.

9. Examiners' Recommendation

The examiners first present their recommended treatment of River Bend costs. They then discuss, and reject, the proposals based upon excess capacity and economic viability. Finally they analyze the proposed disallowances based upon the alleged imprudence of the decision to restart River Bend.

a. *Examiners' proposed treatment of River Bend costs*

(1) Capital cost disallowance. The examiners recommend that 9 percent of River Bend's capital costs be disallowed as imprudently incurred. River Bend end-of-test year investment in River Bend was $3,044,620,982. Simpson suppl. test. at 7. The amount excluded from plant-in-

service would be $274,015,889, leaving remaining River Bend plant in service of $2,770,605,093.

(2) CEPCO buyback capacity costs. The examiners recommend that nine percent of the CEPCO buyback capacity payments be disallowed, and that those payments be calculated on a January-December 1988 rate year. That calculation is set forth in the purchased power section of this report. They reject OPC's proposed amortization of the remaining costs over the life of the plant. As has been stated, the examiners consider the CEPCO payments to be a legitimate expense item prudently incurred.

(3) Deferred River Bend expenses. The examiners agree with GSU that the most recent deferred expense data available should be used in calculating the amount to be placed in rate base in this docket. The most recent actual data in evidence, however, was that used by Mr. Bellon. Therefore for the purposes of this report, only actual cash expenses through January 1987, along with return on those expenses, return on investment, depreciation, and decommissioning expense through December 1987 should be included in GSU's rate base. Remaining expenses should be included in rate base in GSU's next rate proceeding. With its exceptions to this report, however, GSU should file up-to-date actual expense figures, and should provide the related workpapers to the parties. If the parties are able to stipulate to the accuracy of GSU's calculations, the most recent cumulative deferred expense amounts should be included in rate base. Deferred depreciation and return should be reduced to conform with the examiners' nine percent disallowance. A total of $603,235,728 in deferred expenses should be included in rate base. The examiners' recommendations increase total deferrals by $176,457,819 over the staff's recommended level. The increase is primarily due to the examiners' inclusion of deferred return, depreciation, and decommissioning expense through December rather than June.

In its interim order in this proceeding the Commission stated,

> 5. GSU shall develop a plan to offset its River Bend related rate base accounts for Texas retail rate-making purposes by an amount of $1.50 for each dollar of interim increase collected from Texas retail ratepayers under this order, and shall by written filing within 10 working days after the date of this order inform the Commission of its proposed procedure to effect such offset. Because of the uncertainty raised by GSU as to the effects on Dr. Hadaway's original proposal on various taxation requirements the utility must meet, Commission invites the parties to address the details of this accounting in the hearing on the merits of the permanent rate request.

The parties accepted the Commission's invitation. The examiners agree with the Cities and North Star that deferred expenses should be offset by 1.5 times the interim revenues collected by GSU, not by .90 times that amount as proposed by GSU to recognize tax effects. The interim increase gave rise to no current federal income tax liability. The Cities are also correct that the tax effect, if any, from $1.00 of interim rates would be $.34 not $.60. Therefore even if the Commission accepts GSU's position on deferred taxes, the offset should be $1.50 minus $.34, or $1.16. Under Mr. Bellon's proposal, the 1.5 times offset would be imposed in GSU's next rate case, as significant deferred expenses would remain outstanding. If GSU can produce up-to-date deferred expense figures, however, the offset should be applied in this case.

The Cities suggested that no return be allowed on deferred cash expenses. The examiners disagree. Return on those deferred cash expenses clearly is contemplated by the stipulation in Docket No. 6525. The Cities also proposed to reduce the deferred expenses to be included

in rate base by the amount of excess deferred taxes held by GSU. The Commission rejected that proposal in the recent WTU case, Docket No. 7510. As the examiners in that docket observed, any excess deferred taxes would serve to reduce the company's rate base. Examiners' Report at 40-41. The examiners recommend that the Commission follow its course in the WTU case and require no such offset to deferred River Bend expenses.

In *WTU*, the Commission ordered amortization of deferred plant expenses over a 40-year period, as also proposed by the Cities here. FASB 92 allows that treatment. In this case GSU recommended amortization over an eight-year period, the staff over a ten-year period. The examiners recommend amortization over a 40-year period. Amortization over 40 years would recognize that deferred accounting is extraordinary regulatory treatment and that the deferred accounting order was fulfilled its purpose of protecting GSU's financial condition during this period of regulatory lag. GSU offered two reasons for a shorter period. The first, anticipated FASB requirement, is no longer valid. The second, the company's financial condition, is best addressed via the rate moderation plan rather than by the accelerated recovery of deferred expenses.

(4) Rate moderation plan. Whatever rate moderation plan the Commission adopts should meet the requirements of SFAS 92. Although FASB standards do not control this Commission, the examiners can see no reason to depart from FASB requirements in this case. A write-off of a portion of deferred River Bend revenues for financial reporting purposes could damage the company even if investors were aware that those costs were to be recovered beyond the tenth year of the rate moderation plan. It would be unwise to trifle thus with GSU's financial health.

Only four phase-in proposals—GSU's, North Star's, and the staff's two alternatives—envision recovery within ten

years as required by SFAS 92. The examiners agree with all the other parties that GSU's plan would place River Bend in rates too quickly. North Star showed that GSU's key financial indicators would skyrocket to AA or AAA levels within three years under GSU's plan. North Star Ex. 12. Standard and Poor's financial criteria for pre-tax interest coverage and cash flow as a percent of permanent capital associated with various bond ratings are set forth below:

	'AAA'	'AA'	'A'	'BBB'	'BB'
Pretax Interest Coverage (Excl. AFUDC*)—	Greater than X 4.5	3.5-50.	2.5-4.0	1.5-3.0	Less than 2.0
Net Cash Flow/ Permanent Capital—%	Greater than 10.0	7.0-11.0	5.0-8.0	2.5-6.0	Less than 3.0

* Also excludes other non-cash accruals.

GSU's plan would endeavor to produce the following indicators in the first four years:

	Year 1	Year 2	Year 3	Year 4
Pre-Tax Interest Coverage (Excl. AFUDC)	1.30x	2.41x	3.53x	4.38x
Net Cash Flow/ Permanent Capital	3.99%	9.63%	14.52%	17.42%

GSU's plan offers inadequate protection to the company's ratepayers. GSU need not reach a 1.0x interest coverage level in the first year in order to meet its actual cash expenses, as depreciation, a non-cash item, was included in the company's calculation.

North Star's plan would produce the following indicators, as calculated by the company:

	Year 1	Year 2	Year 3	Year 4
Pre-Tax Interest Covreage (Excl. AFUDC)	.67x	1.16x	1.43x	1.74x
Net Cash Flow/ Permanent Capital	.73%	3.54%	5.10%	6.47%

North Star was able to show that its plan would allow the issuance of first mortgage bonds within the second year.

The staff's rate moderation plans, incorporating its proposed disallowance, would produce the following indicators as calculated by GSU:

	Year 1	Year 2	Year 3	Year 4
Staff 4/10 Plan:				
Pre-Tax Interest Coverage (Excl. AFUDC)	.76x	1.42x	2.08x	2.58x
Net Cash Flow/ Permanent Capital	1.42%	5.01%	8.35%	10.66%
Staff 5/10 Plan:				
Pre-Tax Interest Coverage (Excl. AFUDC)	.74x	1.31x	1.86x	2.41x
Net Cash Flow/ Permanent Capital	1.26%	4.34%	7.11%	9.64%

The staff's plans with no disallowance would produce the following indicators, as computed by GSU:

	Year 1	Year 2	Year 3	Year 4
Staff 4/10 Plan:				
Pre-Tax Interest Coverage (Excl. AFUDC)	.84x	1.60x	2.37x	2.99x
Net Cash Flow/ Permanent Capital	1.91%	5.76%	9.47%	12.37%
Staff 5/10 Plan:				
Pre-Tax Interest Coverage (Excl. AFUDC)	.80x	1.47x	2.14x	2.82x
Net Cash Flow/ Permanent Capital	1.70%	5.03%	8.17%	11.24%

The examiners recommend adoption of the staff's proposed 4/10 rate moderation plan. Mr. Reilley showed that GSU would be able to cover its actual cash obligations under that plan in the first year and that his plan would provide a stable rate pattern for long-term recovery. The examiners have selected the 4/10 plan over the 5/10 plan to avoid the additional cost resulting from the inclusion

of deferrals in rate base over a longer period of time. Moreover, the 5/10 plan contemplates progressively larger rate increases in years three, four, and five, which appears to violate section (d) of SFAS 92.

Either North Star's 20 percent or its 30 percent plans would also produce adequate financial indicators. As those are based on partial deregulation of the plant, however, the examiners do not recommend their adoption. Moreover, North Star's erratic rate pattern appears to violate SFAS 92(d).

The staff's rate moderation plan was designed to recover particular revenue requirements to meet certain financial criteria, and particularly the ability to meet cash expenses, in the first year. Thus the first year of the plan is oriented toward financial results. For that reason, the staff's recommended first-year increase without any prudence disallowance was approximately the same as the staff's recommended first-year increase with a prudence disallowance. Also for that reason, the examiners' recommended first-year revenue requirement is virtually identical to the staff's proposal.

The effect of the examiners' changes to the staff's recommendation is to alter the level of revenue deferrals. A comparison of the levels of estimated rate increases and deferrals, on a total system basis, as recommended by GSU, the staff, and the examiners is set forth on page 169A. The estimated system revenue requirements are tabulated and depicted graphically on page 169B [App. 234a-237a].

(5) Contra-AFUDC. Contra-AFUDC should be amortized over 10 years, as recommended by the staff. OPC failed to give convincing reasons for accelerated amortization of that item.

(6) GSU's proposed true-up mechanism. The examiners recommend rejection of GSU's proposed true-up mechanism. SFAS 92 does not require that such a scheme

be in place for deferred revenues to be capitalized. Such a scheme could cause more problems than it solved, moreover, as it may violate PURA Sections 39 and 41 and P.U.C. SUBST. R. 23.21.

b. *Excess capacity/Economic value.* The Cities and TIEC recommended that portions of River Bend investment be excluded from rate base due to excess capacity on GSU's system. Dr. Andersen's phase-in proposal for OPC was also based on that rationale. North Star recommended that 20-40 percent of River Bend be withdrawn from rate base and transferred to a nonregulated subsidy on the grounds of economic viability.

A number of jurisdictions have followed the practice of disallowing investment based on excess capacity or economic value. Two cases, which involved the Susquehanna 2 and the Wolf Creek nuclear power plants respectively, explain the rationale for an adjustment based on excess capacity or lack of usefulness:

> The primary meaning of "*useful*" in the present context is that the plant and its associated capacity contribute no more than necessary to system reliability in the accepted, technical sense. In other words, the question is whether the company's total capacity, including the plant in question, is commensurate with the requirements for peak demand plus a reasonable reserve margin relative to the company's own system and to its PJM obligation.
>
> This is the heart of any excess capacity determination. It means, among other things, that the company's alternative definitions of "reliability" as fuel diversity or available capacity are peripheral. If there is excess capacity in the primary reliability sense, then the threshold condition for an adjustment has been satisfied. *Pennsylvania Public Utility Commission v. Pennsylvania Power & Light Company*, 67 PUR4th 30, 43 (Pa. P.U.C. 1985).

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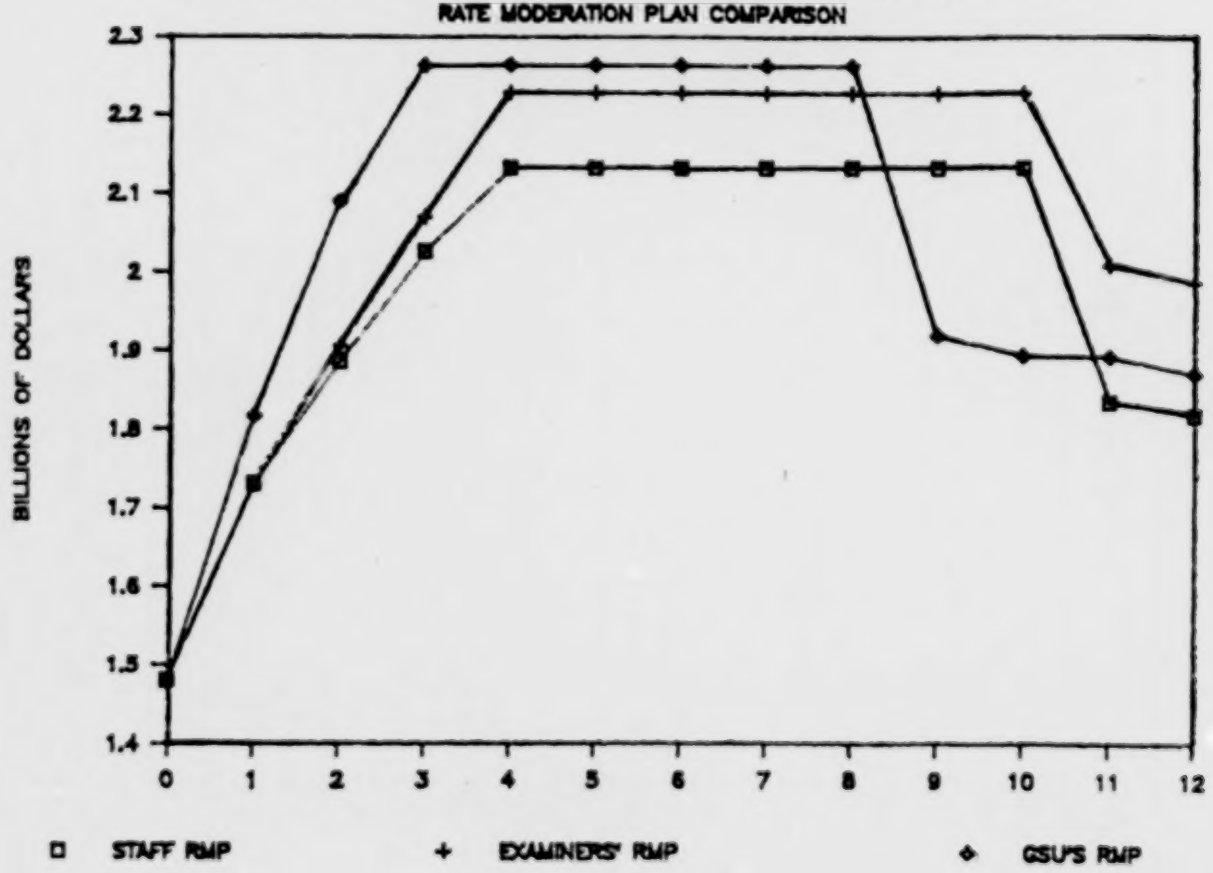
Summary Table on Rate Moderation Plans
(Total System Basis)

Year	GSU Proposed *	Supplemental Staff 4 Increase * Alternative	Examiners' Recommendation
Estimated Rate Increases			
1	336,400,000	250,400,000	249,500,000
2	272,300,000	155,000,000	175,000,000
3	174,000,000	140,000,000	165,000,000
4	0	106,500,000	157,650,000
5	0	0	0
6	0	0	0
7	0	0	0
8	0	0	0
9	0	0	0
10	0	0	0
TOTAL	782,700,000	651,900,000	747,150,000
Deferrals (and Amortizations)			
1	575,000,000	461,684,000	442,391,000
2	252,400,000	333,100,000	377,800,000
3	28,350,000	158,600,000	189,600,000
4	(32,450,000)	21,900,000	8,450,000
5	(131,650,000)	(66,050,000)	(77,600,000)
6	(179,000,000)	(108,359,000)	(117,350,000)
7	(228,000,000)	(137,350,000)	(145,950,000)
8	(284,650,000)	(177,950,000)	(185,500,000)
9	0	(218,850,000)	(226,500,000)
10	0	(266,734,000)	(265,341,000)
TOTAL	0	0	0

* Source: Staff Exhibit 74 Schedule IV.

Note: The information in each colum is based on somewhat different revenue requirement assumptions.

ESTIMATED SYSTEM REVENUE REQUIREMENTS



Total Annual Revenue Requirements

GSU RMP	Staff Four Increase RMP	Examiners' RMP
1,480,583,000	1,480,583,000	1,480,583,000
1,817,021,116	1,730,957,513	1,730,098,892
2,089,301,843	1,885,929,213	1,905,144,749
2,263,254,951	2,025,912,021	2,070,173,836
2,263,262,403	2,132,430,556	2,227,832,119
2,263,302,001	2,132,438,569	2,227,835,090
2,263,255,120	2,132,434,510	2,227,866,677
2,263,219,703	2,132,421,784	2,227,897,432
2,263,190,279	2,132,404,975	2,227,920,201
1,918,519,057	2,132,412,513	2,227,900,366
1,893,642,821	2,132,453,263	2,227,904,922
1,891,574,673	1,834,877,948	2,008,692,468
1,870,322,000	1,817,576,900	1,987,006,156

Note: The information in each column is based on somewhat different revenue requirement assumptions.

> The Commission's duty to balance investor and consumer interests does not amount to a guarantee that utility management is operating in a risk-free environment and thus the shareholder's investment is also risk free. Utility management took the risk that the Wolf Creek unit would not be needed when the construction plan was complete. *Re Kansas Power and Light Company*, 75 PUR4th 1,125 (Mo. PSC, 1986).

For other citations, *see* Cities initial brief at 6-9, 12, 51-59, 70-71; North Star initial brief at 9.

The Oregon Commission has rejected that interpretation of "used and useful," however.

> The proposition that Colstrip No. 3 should be excluded from rate base because it has come on line during an energy surplus is also unsound from a regulatory policy standpoint. Specifically, the argument ignores not only the public service obligation of utilities, but also the realities of resource planning and the adverse financial consequences that would inevitably ensue for the utility and its ratepayers.
>
> Under current economic conditions, the time necessary to complete construction of a major generating facility ranges from six to twelve years. If the on-line date of a plant happened to coincide with an energy surplus, the [Utility Reform Project] would assign all cost responsibility to the utility's shareholders, regardless of whether the original decision to construct the plant was reasonable and prudent. This approach to rate making would have extremely undesirable consequences.

Those undesirable consequences included greater riskiness of utility securities, resulting ultimately in higher capital costs, and a greater likelihood of energy shortages due to utility reluctance to construct base load generating capacity. *Re Pacific Power & Light Co.*, 63 PUR 4th 642, 645-46 (1984). For other citations, *see* GSU's initial brief at II-39—II-57.

State courts have generally upheld commissions' interpretations. In a recent case, though, the Louisiana Supreme Court upheld a district court decision which reversed the Louisiana Commission's denial of a rate increase to Central Louisiana Electric Company (CLECO). The Commission's decision had been based in part on the fact that CLECO's Dolet Hills coal unit created "overcapacity" on CLECO's system. The Louisiana Supreme Court stated,

> Overcapacity, however, must be looked at realistically. "As a matter of sound business judgment,

> utilities must build beyond their immediate needs. If their investments are provident and are made both in good faith and in the best interests of the area served, they plainly belong in the ratebase." Priest at 181. . .
>
> The long term best interests of ratepayers is not promoted by penalizing utilities for excess capacity via rate base exclusions or by denying the company a return on a completed facility while simultaneously taking full advantage of its operating efficiency. Berlin, Excess Capacity, Plant Abandonments, and Prudent Management, 114 Pub. Util. Fort. 26, 29 (Nov. 22, 1984).

CLECO v. Public Service Comm'n, 508 So.2d 1361, 68 (La. 1987).

As the Texas courts have not reached the issue, the treatment of excess capacity would appear to be a matter for this Commission to decide based on its view of the law and public policy.

In GSU's previous rate case, Docket No. 6525, 12 P.U.C. BULL. 1043 (Oct. 15, 1986), Judge Drews discussed this issue in some detail in relation to the proposed disallowance of capacity payments for power purchased by GSU from the Southern Companies. Although those payments were expenses to be treated under the "reasonable and necessary" provisions of PURA Sections 39(a) and 41(c)(3)(D), Judge Drews observed that the standard to be applied to long-term power contracts was similar to that applied to construction of major generation since the two are alternative ways of meeting load. She rejected the use of a standard based on present necessity and concluded instead that reasonableness should be determined as of the time the decision was made. 12 P.U.C. BULL. at 1088-92.

The Commission declined to adopt Judge Drews' proposed conclusion of law on the issue as unnecessary to

its decision in the case. 12 P.U.C. BULL. at 1255, 1283. The examiners in this docket, however, agree with Judge Drews' analysis and recommend rejection of the Cities, TIEC, North Star proposals summarized above. They concur with GSU that any disallowance based upon unfortunate results, as opposed to imprudence, is unfair. For example, the benefits of the low-cost long-term Exxon gas contract for many years were flowed through to GSU's ratepayers. It would be unjust for GSU's shareholders to be left to pay for the admittedly high costs of River Bend unless those costs were imprudently or wastefully incurred. Even Mr. Lawton of the Cities, in cross-examination, appeared to agree with the basic regulatory principles espoused by GSU so long as utility planning is prudent, reasonable, and efficient. Tr. at 10685-96.

If the Commission disagrees and concludes that a non-prudence-based standard should be followed, the examiners recommend adoption of either the Cities' slice-of-the-system average cost recommendation or North Star's proposal, with modifications. Although the addition of River Bend does offer some advantages to GSU in fuel cost, diversity, and flexibility, the company clearly has excess generating capacity as that term is generally used. The company should not be allowed to evade the consequences of that situation by placing 443 MW of previously used generation in cold storage; therefore those units should be considered in calculating the capacity available. The examiners consider Mr. Lawton's 30 percent reserve margin to be a reasonable point from which to calculate an excess capacity adjustment, in light of the Southwest Power Pool's 18 percent reserve criterion and the decisions of other jurisdictions which have applied the excess capacity concept. Mr. Smith's reference to a 40 percent reserve margin as reasonable was merely a variation on the prudence standard, while Mr. Pollock's use of 18 percent was unduly rigid.

The examiners agree, however, with Mr. Pollock's exclusion of 252-303 MW of interruptible load from GSU's

peak forecast. GSU does not design its capacity expansion plan to serve interruptible load, Tr. Vol. 95 at 14785. In its rate design brief, GSU admitted that the interruptible load should not be included. GSU brief at 54. Reducing the peak load forecast would increase Mr. Lawton's excess MW, which would be calculated as follows:

Year	Peak	System Resources	Percent Reserves	Excess MWs
1986	4837	7483(1)	54.8%	1195
1987	4727	7169(2)	51.7%	1024
1988	4221	7105(3)	50.5%	938
Average	4762	7252	52.4%	1052

Those excess MWs multiplied by $693/kW as recommended by Mr. Pous would yield a reduction to rate base of approximately $729 million.

If adopted, the modified Cities proposal would have to be combined with a specific phase-in plan to ensure the recovery of allowed River Bend costs not covered by the first year increase. The satellite issues such as deferred expenses should still be resolved as set forth in the examiners' recommendations, with the amounts modified to conform with the amount of rate base disallowance.

North Star's proposal would probably be legally acceptable under a liberal interpretation of the "used and useful" test. GSU rebuttal witnesses Willis and Beekman raised the serious possibility that the North Star plan could require a write-off of up to $800 million rather than the $74 million envisioned by Dr. Hadaway. Although he deemed it highly unlikely, Dr. Hadaway himself did not rule out that possibility. Tr. Vol. 59 at 9363-65. Although such an uncertain financial impact seems inappropriate in a plan premised on financial considerations, the evidence shows that GSU could survive under either North Star's 20 percent or its 30 percent "deregulation" scenario. If adopted, North Star's plan should be

revised to ensure compliance with all the criteria of SFAS 92.

c. *Proposals based upon alleged imprudence of the restart decision.* Because the examiners find the restart decision to have been prudent, they reject the parties' proposed disallowances based on that decision. They analyze the proposals briefly below, however, as the Commission might reach a different conclusion. Three parties —PPC, OPC, and the staff—recommended disallowances on that basis. The examiners reject Mr. Komanoff's proposal. That proposal ignored the fact that GSU would have been compelled to build coal or lignite capacity if it had cancelled River Bend. Mr. Komanoff's recommendation was not really prudence-based, but rather was based on present economic efficiency. It did not reflect the choices open to GSU at the time of the restart decision.

The examiners also reject MHB's $300-500 million adjustment based upon its analysis of Mark III costs. The examiners do not find MHB's estimate of those costs to be credible. Nor should uncertainty as to Mark III issues have prevented GSU from building River Bend.

Both Dr. Andersen's and Dr. Pflaum's proposals have appeal. Dr. Andersen's $1.4 billion disallowance was logical and clearly founded on the ultimate costs of the coal alternative open to GSU in 1979. Dr. Pflaum's, on the other hand, was based solely upon Mr. Hadzi-Pavlovic's recommended DCE and Dr. Pflaum's own subjective opinion as to what capital cost would have made River Bend a "go." The error in his original calculation would reduce his disallowance to $261 million. Under his plan, ratepayers would pay a considerable amount more than they would have if GSU had chosen to cancel River Bend and build coal capacity. Yet Dr. Pflaum's proposal did recognize that GSU had no idea in 1979 that River Bend would cost nearly as much as it actually has and that a $1.4 billion disallowance is far beyond what anyone might have expected at that time.

Dr. Andersen's was the most thoroughly considered of the prudence-based proposals. The Commission might wish to exercice some sort of risk-sharing, however, to take into account the consideration raised by Dr. Pflaum. Again, the satellite issues should be decided in accordance with the examiners' recommendations, though the buyback deferred expense, and depreciation amounts, should be adjusted to reflect the amount of capital cost disallowance.

* * * *

XV. Findings of Fact and Conclusions of Law

The examiners recommend that the Commission adopt the following findings and conclusions. The schedules referred to in the findings and conclusions are attached to the Proposed Order for purposes of this Report; if the findings and conclusions are adopted by the Commission, the schedules referred to will be those attached to the Final Order.

A. *Findings of Fact*

1. On November 18, 1986, GSU filed an application to increase its rates within the unincorporated areas in which it serves and in those incorporated areas which have ceded jurisdiction to the Commission.

2. All Texas customers and classes of customers over which the Commission exercises original rate jurisdiction would be affected by GSU's proposed changes.

3. By examiners' order dated November 19, 1986, operation of the proposed rate schedules was suspended until May 22, 1987, or until a superseding order is issued.

4. GSU filed publishers' affidavits affirming that it has published a statement of intent in a conspicuous form and placed once each week for four consecutive weeks before the effective date of the proposed changes in newspapers of general circulation in each Texas county in which it serves.

5. GSU filed affidavits affirming that it has individually notified affected municipalities and its customers of the proposed rate changes.

6. GSU has appealed the ratemaking ordinances of the following municipalities that have retained original ratemaking jurisdiction, and the appeals have been consolidated into this case: Anahuac, Beaumont, Bremond, Bridge City, Bevil Oaks, Cleveland, Chester, Corrigan, Colmesneil, Crystal Beach, Cut-N-Shoot, Conroe, China, Devers, Groves, Huntsville, Houston, Kountz, Lumberton, Madisonville, Montgomery, Nederland, Nome, New Waverly, Normangee, Orange, Panorama Village, Pine Forest, Pinehurst, Port Neches, Port Arthur, Roman Forest, Rose Hill Acres, Rose City, Shenandoah, Shepherd, Sour Lake, Silsbee, Somerville, Trinity, Vidor, West Orange, Willis, Woodloch and Woodville.

7. GSU's quality of service and handling of customer complaints are adequate.

8. GSU's conservation efforts are sufficient to justify a zero adjustment to the company's return on invested capital.

9. River Bend is a BWR located near a bend in the Mississippi River just south of Saint Francisville, Louisiana, and about 28 miles north of Baton Rouge.

10. River Bend has a nominal generating capacity of 940 MW and a net rating of 934 MW.

11. GSU owns a 70 percent (658 MW) share of River Bend and Cajun Electric Power Cooperative (CEPCO) owns a 30 percent share.

12. Under a buyback agreement first signed in 1979 and modified in 1986, GSU is obligated to buy 70 percent of CEPCO's share of River Bend power the first year of the plant's operation, 56 percent the second year, 42 percent the third year, 28 percent the fourth year, 19 percent the fifth year and none in subsequent years.

The cost of the buyback is based in part upon the capital cost of River Bend.

13. GSU first announced plans to build River Bend in August 1971. At that time it envisioned building two nuclear generating units at the River Bend site and two at a site in Texas known as Blue Hills.

14. GSU received a Limited Work Authorization for River Bend in September 1975. In 1977, site preparation neared completion and preparation for structural construction began. The NRC issued construction permits in March 1977 for River Bend Units 1 and 2.

15. During 1977, GSU reassessed its planning objectives. Reduced load growth and the desire to maintain high financial indicators prompted GSU to curtail its construction budget and stop work on River Bend.

16. On August 1, 1978, GSU's top management and some of its directors met and reached a tentative decision to resume construction on River Bend 1, decouple and continue to defer River Bend 2, and cancel the Blue Hills units. The decision to resume construction of River Bend 1 was endorsed by the Board of Directors in February 1979. River Bend 2 was ultimately cancelled in January 1984.

17. In December 1978, after evaluating proposals from four companies, GSU chose to retain Stone and Webster Engineering Corporation (S&W) as constructor for River Bend.

18. S&W, which also remained as architect-engineer, committed to a River Bend construction schedule which would employ the Nuclear Power Construction Stabilization Agreement (NPCSA) and rolling four-ten work shifts to complete the construction of the plant, from the first concrete pour to the loading of fuel, in 50 months.

19. Actual construction of River Bend 1 resumed in August 1979 with the placement of rebar for the con-

crete basemat. In September 1979 the first concrete was poured and S&W provided GSU with a definitive cost estimate (DCE) that the plant would cost a total of $1.729 billion, including AFUDC.

20. In October 1981, GSU extended the construction schedule of River Bend from 50 months to 68 months. That estimate was later increased to 72 months. Fuel loading commenced in August 1985.

21. River Bend entered commercial operation on June 16, 1986.

22. The total capital cost of River Bend, including AFUDC, is approximately $4.5 billion.

23. River Bend's cost per kW is nearly $4,800, making it the fourth or fifth most expensive nuclear plant built in this country on a per-kW basis.

24. GSU's share of River Bend's capital cost at the end of the test year was $3,044,620,982.

25. If GSU were seeking to recover a return on its entire end-of-test-year share of River Bend in this proceeding using traditional ratemaking it would be seeking a first-year Texas retail rate increase of $359.9 million.

26. The driving forces behind the decision to restart River Bend were the resurgence in load growth GSU experienced in 1977 and 1978 and its projected future growth of approximately six percent annually.

27. GSU's annual peak load growth, which had ranged from two to four percent during the period 1974 through 1976, increased to approximately 12 percent in 1977 and 10 percent in 1978.

28. Adding to GSU's capacity needs was the passage in late 1978 of the federal Industrial Power Plant and Fuel Use Act (Fuel Use Act) which mandated that utilities be weaned completely from gas-fired base load generation by 1990. At that time, GSU was almost completely gas-fired.

29. GSU's annual peak load growth had exceeded five percent in every year except 1953, 1974, 1975 and 1976 at the time the River Bend restart decision was made.

30. GSU's load forecasting was flawed in its failure to account for the effects of price elasticity.

31. Projected load growth of three to four percent would have been appropriate in late 1978 and early 1979.

32. GSU could not have projected the disastrous slump in its service area's economy in the early 1980's.

33. GSU's predicted load growth was consistent with its historical pattern and with the projections of neighboring utilities.

34. GSU legitimately foresaw a need for significant new generating capacity due to projected load growth and the Fuel Use Act.

35. Because of its high capital cost GSU would have abandoned River Bend in 1978-79 in favor of another form of generation if not for the approximately $400 million in sunken and cancellation costs involved in that course of action.

36. The GSU officials present at the August 1, 1978, River Bend meeting expressed serious concern about the impact of a River Bend related write-off on the company's shareholders and on the company's ability to finance other necessary construction.

37. Less than half of total sunken and cancellation costs in 1979 would have been recovered from tax savings.

38. The potential write-off of River Bend in 1979 would have been the largest theretofore experienced for a nuclear project.

39. GSU's concern over the potential impact of the write-off of a portion of River Bend costs was not unfounded, even though GSU did not have a specific write-off number in mind above which its financial ability would be impaired.

40. The mere deferral of River Bend in 1979 would not have triggered a write-off.

41. GSU did not seriously consider continued deferral of River Bend in 1978-79.

42. In the face of load growth, the legitimate need for additional capacity, and escalating nuclear costs, GSU was not imprudent in deciding to either build or cancel River Bend in 1978-79.

43. In 1978-79, management did not know exactly how it would go about financing the completion of River Bend, particularly without participation by other utilities or significant rate relief from Louisiana.

44. The fact that GSU was not sure how it would finance River Bend does not mean that GSU thought the plant would bring it to the brink of financial disaster.

45. GSU's chief financial officer informed management in August 1978 that River Bend could be financed.

46. GSU was not imprudent in expecting some rate relief during the construction of River Bend, especially in Texas at that time.

47. In 1978, GSU could reasonably calculate $350 million in additional first mortgage bond issuance capacity above the $1.3 billion plant estimate used in the 1978 Restart Study. That amount did not include participation or other sources of financing.

48. GSU took reasonable steps to ensure that adequate financing was available for River Bend.

49. CEPCO began negotiating for a share of River Bend as early as 1974 or 1975 and had expressed continuing interest since that time. GSU and CEPCO reached a handshake agreement on participation in January 1979 and a signed agreement in August of that year. All

problems had generally been worked out by February 1979.

50. GSU had no reason to expect difficulties in receiving REA approval of CEPCO's participation in River Bend.

51. GSU was reasonable in its belief that participation by CEPCO in River Bend was forthcoming in 1978-79.

52. Louisiana's December 1978 rate decision, granting a $22.8 million increase, was unexpected and improved GSU's financial prospects.

53. It would have been unreasonable for GSU to have placed too much faith in continued rate relief in Louisiana.

54. GSU's 1978 Restart Study, while giving GSU a rough idea of its financing capacity, was deficient. The study used an unreasonably low capital cost figure and did not model the financial consequences of inadequate rate relief.

55. In the 1977 "Planning For Its Growth" report, GSU's Strategic Planning Committee advocated that the company sacrifice its commitment to reliable service in order to approve its earnings per share and interest coverage ratios, achieve an "AA" bond rating, and increase its dividends.

56. For GSU to have continued pursuing the 1977 study's goals in 1978-79, in light of the perceived need for new capacity, would have been very irresponsible.

57. None of the studies and analyses presented in this docket even remotely suggest that, given 30 percent participation, GSU would have courted financial disaster from financing total River Bend costs as high as $2.6 billion.

58. Given CEPCO's participation, GSU could have financed River Bend readily at any cost level reasonably expected in 1979.

59. GSU did believe that River Bend would diversify its fuel mix and that it would be cheaper than coal-fired generation over the life of the plant, but those factors did not weigh heavily in the deliberations over the decision to restart the plant.

60. After the August 1, 1978, meeting GSU continued, without success, to attempt to sell River Bend.

61. The tentative decision made at the August 1, 1978, meeting was to build River Bend as fast as possible and thus reduce the financial burden from construction as much as possible.

62. In late 1978 and early 1979, GSU had sufficient information to reach a decision and should have reasonably expected River Bend to cost somewhat less than $1.7 billion, which was the high end of the estimate presented to the Board in February 1979.

63. GSU was not imprudent in making the restart decision before ordering preparation of the DCE.

64. The September 1979 DCE was prepared according to industry and S&W practice by breaking down the job into its various components and applying effective unit man-hour rates. The process was thorough and the rates used realistic.

65. GSU actively monitored S&W's preparation of the DCE and had reason to believe that S&W's forecast was accurate and fairly represented the scope of work to be performed.

66. GSU asked S&W a number of questions concerning the scope of work to be covered by the DCE, escalation, man hours levels, headquarters cost, and probable levels of confidence in various aspects of the DCE.

67. GSU was actively involved in monitoring and questioning the assumptions underlying the DCE. There was a continual interchange of queries and information between Mr. Schultz of S&W and Dr. Weigand of GSU.

68. GSU was prudent in its control and monitoring of S&W's preparation of the DCE.

69. The computerized S&W Engineering Management System (EMS) was seriously flawed in 1979. The system was not prepared for the 50-month schedule.

70. More GSU engineers at S&W's headquarters or an earlier audit of EMS would not necessarily have significantly improved the DCE.

71. The 50-month schedule, which was shorter than any theretofore achieved, was 11 months shorter than Bechtel's 61-month rebid proposal, which also used rolling 4-10 workshifts.

72. GSU did not perform any independent evaluation of the 50-month schedule.

73. Adoption of the 50-month schedule was based on the assumption that GSU could financially support the schedule, a proposition which was not tested beforehand and which proved to be untrue.

74. Adoption of the 50-month schedule was based on the assumption that vendor deadlines could be moved forward to meet the new schedule. That proposition was untested, and GSU and S&W indeed had serious problems with vendors' ability to meet the 50-month schedule's requirements.

75. The 50-month schedule when originally presented was premised on a scope of work identical to that set out in the May 1977 cost estimate—an obviously false assumption.

76. The 50-month schedule was untested and hastily conceived in order to assure that S&W would retain its role as constructor of River Bend.

77. GSU was imprudent in relying upon and pursuing the 50-month schedule.

78. GSU could reasonably have pursued a 60-month schedule, which would have still been quite rapid and would still have meant completion in record time.

79. The DCE should have included approximately $183 million for a 60-month rather than a 50-month schedule.

80. A reasonable manager in 1979 would have expected cost increases attributable to unresolved safety issues and TMI backfits to cost between $50 million and $100 million.

81. GSU should have added $50 to $100 million to the DCE for costs of unresolved safety issues and TMI backfits.

82. GSU generally effectively rebutted OKA's contention that many WPCNs and MCCs were improperly excluded from the DCE.

83. Changes reflected in WPCN 26, WPCN 200, WPCN 29, WPCN 118, and MCC 134, totalling approximately $18.370 million, were wrongly omitted from GSU's September 1979 estimate of plant costs based on the DCE.

84. WPCN 26, in the amount of $1.621 million, added fire protection headers. WPCN 200, in the amount of $2.504 million, pertained to the fireproofing of steel. Both were required by Appendix A which contained NRC fire protection requirements. Those costs should have been foreseen in September 1979.

85. In September 1979 GSU should have been aware of the existence of WPCN 29, which increased design costs of cooling towers by approximately $7.7 million.

86. In September 1979 GSU should have been aware of WPCN 118, which covered $221,000 worth of modifications to the radwaste building bridge crane.

87. In September 1979 GSU should have been aware of MCC 134 which added $6.324 million in additional costs for startup testing activities to be performed by S&W.

88. In September 1979, GSU should have expected River Bend to cost between $1.978 and $2.030 billion.

89. GSU was prudent in not including a formal contingency in its 1979 DCE.

90. GSU was indeed aware of the possibility of cost overruns and was certain of its ability to finance River Bend.

91. An appropriate informal contingency would have been 15 percent of to-go costs to cover not only unknown changes (such as those related to escalation or TMI), but also known but unquantifiable changes (such as the costs of stricter ASMC piping criteria or ongoing vendor negotiations).

92. Sunken costs as of September 30, 1979 were approximately $412 million.

93. Applying a contingency of 15 percent of to-go costs to an expected cost of $2.030 yields a reasonable contingent estimate for financial planning purposes of approximately $2.273 billion.

94. The level of escalation set forth in the DCE was based upon detailed analyses of job components and contracts and on predictions by the President's Council of Economic Advisors.

95. MHB's application of the five-year Handy-Whitman construction cost escalation average of 9.3 percent was simplistic and skewed by an increase of 13.0 percent between 1974 and 1975, the first year of that five-year period. Removal of that year and reliance on a four-year average would yield an annual increase of 8.48 percent—almost identical to the reasonable 10-year average identified by Mr. Curless of GSU, which was in line with the amounts actually included in the DCE.

96. The level of escalation set forth in the DCE was reasonable.

97. One of the three practitioners of the econometric estimating technique, Dr. Perl, in late 1978 disavowed its use as a basis for estimating future plant costs.

98. Use of an engineering estimate, with an appropriate contingency, was appropriate in late 1979 for estimation of River Bend's cost.

99. GSU was not imprudent in failing to consider the results of econometric estimation of nuclear plant costs in 1979.

100. Mark III containment issues appeared close to resolution in 1979.

101. To have included specific amounts for the resolution of Mark III issues in the DCE would have been speculative. Potential costs more appropriately would have been covered by a general financial planning contingency.

102. MHB predicted in 1978 that resolution of Mark III problems, including delays, would cost between $10 and $30 million.

103. It would not have been prudent to have deferred River Bend construction until Mark III issues were resolved.

104. All straightforward nuclear/coal busbar studies conducted at the level of the DCE suggested an economic cost advantage for nuclear power.

105. Dr. Pflaum's busbar comparison showed a cost advantage for nuclear generation at a $1.95 billion level. Dr. Pflaum found the breakeven point to be $2,300 per kW, or a capital cost of roughly $2.148 billion.

106. Dr. Andersen of OPC determined the nuclear/coal breakeven point to be at a capital cost of $2,135 per kW, or a capital cost of approximately $2.007 billion.

107. Busbar studies conducted at capital cost levels of $1.98 to $2.03 billion for River Bend would have been

inconclusive or have shown a slight advantage for the nuclear option. Adding a 15 percent cost contingency to the nuclear estimate would probably have shown a slight advantage for coal.

108. The results of busbar analyses alone should not dictate generation planning decisions.

109. The financial uncertainties associated with nuclear power, although great, did not seem as overwhelming in 1979 as the ultimate costs of those plants would now imply.

110. Uncertainty as to coal prices, the potential for pollution from coal-fired generation, and the possible financial effects of River Bend cancellation argued in favor of nuclear power and the construction of River Bend.

111. The basic premise of Dr. Andersen's gas displacement analysis was that GSU could have built more coal-fired generation than nuclear generation for the same price. That additional generation would have displaced high-cost gas and helped GSU to meet its obligations under the Fuel Use Act.

112. Dr. Andersen used reasonable cost and technical assumptions in his gas displacement analysis.

113. The benefits of a gas displacement course depended upon the stringence of financial constraints and on predictions as to the volatile price of gas. The benefits of the gas displacement course therefore were themselves uncertain.

114. Dr. Andersen's selection of coal-fired generation as the optimal expansion path due to gas displacement did not take into account uncertainties attributable to coal prices, pollution, and River Bend cancellation.

115. Although Dr. Andersen's gas displacement analysis identified a reasonable alternative available to GSU, it did not show that the path pursued by GSU was imprudent.

116. GSU should not have planned its capacity expansion program on the unsubstantiated fear that its load projections would be drastically wrong.

117. GSU was not imprudent in proceeding with River Bend rather than building 300 MW coal units in order to protect its flexibility against volatile load growth.

118. GSU's decision to restart and build River Bend was prudent.

119. The CEPCO buyback enabled GSU to obtain participation in River Bend and provided power which GSU legitimately believed it would need during the first years of River Bend's operation.

120. The CEPCO buyback was a prudent transaction.

121. The Incremental Estimate File (IEF) was primarily a cost tracking and accounting tool and was not designed to provide a detailed justification of cost increases.

122. The fact that GSU had a legitimate process for reviewing and approving changes in project costs does not show that those costs were reasonable.

123. The guidelines for coding changes to the regulatory category in the IEF limited the informative value of the IEF.

124. The PLG Report's analysis of the reasons for growth in the cost of River Bend was cursory and inadequate.

125. PLG has cited low cost per kW as an indicator of prudent management and as a key measure of management performance in other proceedings. The absence of a cost-per-kW comparison in this case damaged the credibility of the PLG report.

126. Although River Bend showed a relatively good ratio of man/hours per commodity unit, it used more quanti-

ties for eight out of eleven and more man-hours for seven out of eleven commodities reviewed by PLG.

127. The OKA report, although more thorough than the PLG report, reached no conclusions as to imprudence during the construction of River Bend except as regards the 50-month schedule.

128. GSU's attribution of 46 percent of River Bend's cost growth to regulatory causes is not unreasonable.

129. Regulatory requirements unforeseen in 1979 had a significant if unquantified effect on the cost of River Bend.

130. The unique design features identified by Mr. Glazar of GSU did not significantly increase the cost of River Bend.

131. GSU could have developed a far more complete and accurate investigation of the reasons for the growth in River Bend costs.

132. GSU's non-statistical explanations of the reasons for the high capital cost of River Bend were inadequate and unconvincing.

133. At least $74,680,000 was imprudently spent in pursuit of the fuel load to first concrete 50-month construction schedule.

134. GSU has not proven how much of the $74,680,000 it spent in pursuit of the 50-month schedule would have been spent in any event.

135. S&W's engineering effort was inefficient to the point of wastefulness during the first year or so of the project.

136. The inefficiency of S&W's engineering effort was due at least in part to the rapid resumption of plant construction.

137. Pursuit of the 50-month schedule reduced construction productivity.

138. S&W's Engineering Management System (EMS) was in disarray through at least 1980.

139. Problems with EMS were aggravated by the 50-month schedule.

140. At least partly because it could not keep track of engineering status through EMS, GSU put its own engineers at S&W's Cherry Hills Operation Center (CHOC) in April 1980.

141. Problems with EMS deprived GSU of a valuable tool for project control.

142. Problems with EMS, the inefficiency of S&W engineering, and the reduction in productivity from pursuit of the accelerated schedule cannot be quantified accurately.

143. Neither GSU nor S&W was imprudent in the handling of TDI problems.

144. TDI itself was imprudent, as shown by the continual problems which culminated in the failure at Shoreham and the NRC's loss of confidence.

145. The direct costs of TDI problems to GSU totalled $8.1 million.

146. Although other expenses were probably incurred in resolving the TDI problems, MHB's calculation of an additional $54 million in "delay costs" was arbitrary and unsupported by any documentation.

147. GSU's handling of the Mark III problems, including the concrete annulus fill, was prudent.

148. The concrete annulus fill cost only $4 million.

149. Mark III problems caused no constructon delays at River Bend.

150. MHB's calculation of $300-$500 million in total post-1979 Mark III costs was completely unsupported and cast doubt on its entire analysis of the Mark III issue.

151. The cost of the pursuit of the 50-month schedule, engineering, construction, and EMS inefficiency, and TDI problems should be captured in the statistical analysis which is the basis for the exclusion of nine percent of River Bend's capital cost from plant-in-service.

152. The existence of identifiable imprudence and inefficiency in the construction and management of the plant as set forth in Finding of Fact Nos. 133-145 corroborates the exclusion of a portion of River Bend's capital costs from plant-in-service.

153. It was appropirate to include the stop work variable in statistical analyses of River Bend's cost because the purpose of those analyses was to measure the variances in cost among prudently and efficiently managed projects.

154. It was appropriate to include Comanche Peak among the plants covered by the stop work variable solely for the purposes of statistical cost comparisons in this docket.

155. The utility-as-constructor variable was appropriate for use in statistical analysis because GSU should not be expected to perform as efficiently as Duke Power or Commonwealth Edison, with their far greater experienec and resources, in the construction of nuclear power plants.

156. It was appropriate to include a variable for plant percentage complete in 1979 in the statistical analyses because it is plausible that plants not very far along in construction at that time were affected more seriously than others by changing regulatory requirements and increased regulatory scrutiny.

157. Although Dr. Perl excluded Grand Gulf and Perry from his single unit BWR variable group, Perry 2 has been cancelled and Grand Gulf 2 has been deferred indefinitely.

158. River Bend is not fairly comparable to other BWRs because it did not suffer as greatly from Mark III problems.

159. Dr. Perl's single unit BWR variable was not appropriate.

160. The most reliable statistical analysis presented was Dr. Perl's rebuttal of Dr. Pflaum, which included the stop work, utility-as-constructor, and percentage-complete variables but excluded the single unit BWR variable.

161. Dr. Perl's statistical analysis described in Finding of Fact No. 160 showed River Bend to be nine percent more expensive than its expected cost.

162. The fact that River Bend's costs are within a 90 or 95 percent statistical confidence interval does not explain or justify the high cost of the plant.

163. Although statistical analysis is an imprecise measure, it is the best one offered in this proceeding.

164. Nine percent, or $274,015,889, of GSU's share of River Bend's costs should be excluded from plant in service.

165. GSU's proposed rate moderation plan would defer the rate recognition of a portion of River Bend-related revenue requirements from the earliest years of operation to later years. GSU proposed to defer billing its Texas retail customers $202,900,000 of the first year's requirements, $107,800,000 of the second year's, and $49 million of the third year's. The cumulative balance of those deferred revenues would be included in rate base and earn a current return. In years 4-8, GSU proposed to recover the particular year's costs plus a specified percentage of the total cumulative deferred requirement.

166. Nine percent of the CEPCO buyback capacity payment should be disallowed to conform with the percentage of River Bend costs excluded from rate base. CEPCO buyback capacity payments should be calculated on a January-December 1988 rate year.

167. Because the CEPCO payments are a legitimate expense item prudently incurred, they should not be amortized over the life of the plant.

168. Deferred cash expenses through January 1987, along with return on those expenses, return on investment, depreciation, and decommissioning expense through December 1987 should be included [sic] GSU's rate base. Remaining expenses should be included in rate base in GSU's next rate proceeding.

169. Deferred depreciation and return on investment should be reduced by nine percent to conform with the disallowance of nine percent of River Bend's cost from rate base.

170. A total of $602,235,728 in deferred expenses should be included in GSU's rate base.

171. In its interim rate order in this docket the Commission required GSU to offset its River Bend-related deferred expenses for Texas retail ratemaking purposes by an amount of $1.50 for each dollar of interim increase collected from Texas retail ratepayers.

172. The 1.5 times interim revenue offset of deferred expenses should be imposed in GSU's next rate case.

173. GSU did not incur any current tax liability by virtue of the interim rate increase authorized by the Commission in this docket.

174. Deferred River Bend expenses should be offset by 1.5 times the interim revenues collected by GSU, not by .90 times that amount as proposed by GSU.

175. It is reasonable to allow return on deferred cash expenses in rate base.

176. Because excess deferred taxes would serve to reduce the company's rate base, deferred River Bend expenses should not be reduced by the amount of excess deferred taxes held by GSU.

177. Amortization of deferred expenses over 40 years would recognize that deferred accounting is extraordinary regulatory treatment and that the deferred accounting order in Docket No. 6525 has fulfilled the purpose of protecting GSU's financial condition during a period of regulatory lag.

178. Deferred River Bend expenses should be amortized over a 40-year period.

179. A write-off of a portion of deferred River Bend-related revenues for financial reporting purposes could damage the company even if investors were aware that those costs were scheduled to be recovered after the tenth year of the rate moderation plan.

180. Any rate moderation plan the Commission adopts should meet the requirements of SFAS 92.

181. Only four phase-in proposals—GSU's, North Star's and the staff's two alternatives—envision recovery of deferred revenues within ten years as required by SFAS 92.

182. GSU's, North Star's and the staff's rate moderation proposals would all achieve financial indicators sufficient to ensure GSU's short-term survival and long-term recovery.

183. Under GSU's plan, its key financial indictors would skyrocket to AA or AAA bond rating levels within three years.

184. GSU's rate moderation plan would offer inadequate protection to the company's ratepayers.

185. GSU need not reach a 1.0 times interest coverage level in the first year of the rate moderation plan in order to meet its actual cash expenses, as depreciation, a non-cash item, is included in the company's calculation of interest coverage.

186. Either of the staff's proposed rate moderation plans would enable GSU to cover its actual cash obligations in

the first year and would provide a stable pattern for long term recovery.

187. The staff's 4/10 rate moderation plan would produce pretax interest coverage (excluding AFUDC) of .76 times in the first year, 1.42 times in the second year, 2.80 times in the third year, and 2.58 times in the fourth year. The staff's 4/10 rate moderation plan would produce net cash flow to permanent capital ratios of 1.42 percent in the first year, 5.01 percent in the second year, 8.35 percent in the third year, and 10.66 percent in the fourth year.

188. The staff's 5/10 rate moderation plan, compared to the 4/10 plan, would result in additional costs from the inclusion of deferrals in rate base over a longer period of time, and would produce progressively larger rate increases in the third, fourth, and fifth years.

189. The rate moderation plan should achieve the short-term financial criteria achieved by the plans proposed by the staff.

190. Application of the staff's 4/10 rate moderation plan to the prudently incurred costs of River Bend would ensure GSU's short-term survival and provide a stable pattern of rate increases to promote long-term recovery.

191. The staff's 4/10 rate moderation plan should be applied to the prudently incurred costs of River Bend.

192. The rate moderation plan described in Finding of Fact Nos. 190 and 191 above, would produce the deferral and amortization levels shown on Schedule VII attached to the Commission's Order.

193. GSU's proposed true-up mechanism for River Bend-related revenues should be rejected.

194. River Bend contra-AFUDC should be amortized over ten years.

195. River Bend is expected to operate for 40 years or more.

196. A 40-year service life is reasonable for calculating annual depreciation expense for River Bend.

197. River Bend should be depreciated at a 2.5 percent annual rate.

198. Annual River Bend-related depreciation expense, after imposition of a nine percent exclusion, is $69,056,862.

199. The external fund method provides assurance that River Bend decommissioning funds will be available when needed, and should be approved.

200. GSU's cost estimate for River Bend decommissioning expense, including a 25 percent contingency, is reasonable.

201. An inflation-adjusted decommissioning payment stream would ensure that present and future customers pay equal shares of River Bend decommissioning expense.

202. Annual decommissioning expense of $2,060,481 should be included in GSU's cost of service in this docket.

203. TIEC's proposed performance standard is simplistic and its ramifications have not been fully investigated in the couse of this rate proceeding.

204. The evidence does not show that imposition of an interim performance standard for River Bend would be necessary or desirable.

205. The preponderance of the evidence establishes that GSU has a total invested capital with components as set forth in Schedule IV of the Order.

206. GSU's net investment in Nelson Units 1 and 2 should be included in rate base unless the Commission issues a final order in Docket No. 7174 approving the transfer of the units to a joint venture before it issues a final order in this case.

207. The preponderance of the evidence supports approval of the uncontested items in net electric plant in service requested by GSU.

208. It is appropriate to adjust accumulated depreciation as requested by GSU to reflect the transfer of Nelson Unit 7 to the steam department.

209. The staff's adjustments reversing GSU's accumulated depreciation adjustment, which adjusts accumulated depreciation by one-half the incremental amount of depreciation expense, should be adopted for the reasons given by the staff and set forth in section VII.D of this Report.

210. The averaging adjustment to accumulated depreciation, recommended by the Cities, should be rejected because it conflicts with the goal of synchronizing—except for known and measurable changes—company revenues, expenses, and investments at test-year-end levels.

211. In accordance with the parties' stipulation in Docket No. 6525, adopted by the Commission, GSU should be allowed to defer $3,065,619 of accumulated depreciation related to Big Cajun 2 Unit 3.

212. The staff's recommendation to reverse GSU's adjustments to accumulated depreciation to River Bend should be adopted to implement the proper deferral of the depreciation expense associated with the plant.

213. The $49,491,492 of deferred payments to Stone and Webster are contractual obligations that are in effect a promissory note in lieu of immediate payment; the payments thus represent a capital expense that should be included in rate base, and a like amount should be included in the total capitalization of GSU as an interest-free loan.

214. The Cities' recommendations pertaining to the capitalized River Bend advertising expenses and the accural

of AFUDC on River Bend should be rejected for the reasons stated in section VII.C.4 of this Report.

215. GSU does not have definite plans to place the Blue Hills site in service within 10 years; accordingly, the company's $4,215,997 investment in the land and the associated transmission lines and rights-of-way should not be included in PHFU.

216. GSU does not have definite plans to place the equipment at Nelson Unit 5 in service within 10 years; accordingly, the company's $23,343,000 investment in the equipment should not be included in PHFU.

217. GSU does not have definite plans to place the following units in service within 10 years: Neches Units 4, 5, and 6 and Louisiana Units 7, 8, and 9; accordingly, the company's investment in these units should not be included in PHFU.

218. Since GSU did not provide data for Neches Unit 8 separate from the data for Neches Units 4, 5, and 6, expenditures associated with Neches Unit 8 cannot properly be included in PHFU even though that unit would otherwise have qualified for inclusion in invested capital.

219. GSU's requested amount for materials and supplies should be reduced by $640,264 to allow for the downward trend in the company's inventory levels during and since the end of the test year.

220. The staff's recommended fuel inventory for GSU of $9.1 million should be approved for the reasons stated in section VII.E.2 of this Report.

221. The Cities' recommendation to exclude prepayments for liability insurance from rate base should be rejected because the liability insurance is properly part of GSU's cost of service.

222. The Cities' recommendation to exclude $65,092 of coal cost and include $13,576 of prepaid rating service

fees to reflect known and measurable changes should be approved.

223. The staff's adjustments to cash working capital should be adopted for the reasons stated in section VII.E.4 of this Report.

224. The Cities' recommendations with respect to minimum cash balances, coal and materials-and-supplies lead days, federal income tax lead days, and mail float should be rejected for the reasons stated in section VII.E.4 of this Report.

225. GSU's end-of-test-year adjustment of deferred income taxes to reflect a 37 percent income tax rate should be reversed as recommended by the staff because the company will have the benefit of cost-free capital provided by the accumulated deferred income taxes until the relevant timing-differences reverse.

226. GSU need not maintain vintaged deferred tax accounts, because such accounts are not required by the Uniform System of Accounts and the cost of maintaining such accounts would not be justified.

227. GSU's deferred income taxes should be adjusted to reflect a decrease of $3,065,619 in accumulated depreciation related to Big Cajun 2 Unit 3.

228. With the exception of the adjustment related to Big Cajun 2 Unit 3, the staff's recommended adjustments to accumulated deferred income taxes should be approved for the reasons stated in the summary of Mr. McKinney's testimony in section VII.F. of this Report.

229. GSU should be allowed to earn a return on the unamortized audit expense because the expense was a reasonable and necessary expense of providing utility service incurred upon order of the Commission and because the preponderance of the evidence does not show that any specific benefits from the audit accrued to the company's shareholders.

230. According to the preponderance of the evidence, ratepayers have contributed 70 percent of the funds in the safety achievement reserve and the company has contributed 30 percent of the funds; accordingly, the reserve should be reduced by 30 percent of its end-of-test-year level, or $98,705, to enable the shareholders to earn a return on the funds they contributed.

231. GSU's adjustment to the end-of-test-year balance of nuclear fuel Contra-AFUDC should be reversed to consistently eliminate the accumulated depreciation adjustments as recommended by the staff.

232. The appropriate method of determining the rate of return for GSU is to determine the weighted average cost of capital.

233. GSU's rate of return on equity is properly determined by the DCF analysis and risk premium analysis of Dr. Olson and Mr. Bradford, which is summarized in section VII.A. of this Report.

234. The preponderance of the evidence establishes that a reasonable return on equity for GSU is 15.25 percent.

235. For the reasons stated in section VII.B. of this Report, the appropriate capital structure of GSU to be used to determine its return on capital is that for January 1987.

236. The appropriate capital structure cost of capital by classes, and weighted average cost of capital to GSU are as set forth in Schedule VI of the Order.

237. Allowing GSU a return on equity of 15.25 percent and a weighted average cost of capital of 12.27 percent will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

238. The preponderance of the evidence establishes that GSU has a total revenue requirement with components as set forth in Schedule I of the Order.

239. The preponderance of the evidence establishes that GSU's fuel and purchased power expenses are as follows:

	(000s)
Purchased Power	–
Reconcilable	$113,605
Nonreconcilable	178,620
Fuel	
Reconcilable	365,739
Nonreconcilabe	4,096
Total	$662,059

240. Because the evidence in this case is insufficient to determine the proper refund of GSU's overrecovery of fuel expenses, GSU should be ordered to file a refund plan within 20 days of the final order in this case.

241. The preponderance of the evidence establishes an operations and maintenance expense with components as set forth in Schedule II of the Order.

242. The preponderance of the evidence supports approval of the uncontested items of operations and maintenance expense requested by GSU.

243. The unrebutted adjustments recommended by the staff and summarized in section IX.C.2. of this Report should be approved for the reasons stated in that section.

244. For the reasons stated in section IX.C.3.c of this Report, GSU's payroll expense ratio is 80 percent.

245. The proper adjustments for dental insurance and health insurance expenses are those calculated by the staff, which are based on actual, rather than projected, data. The staff's adjustments to the company's requested amounts are presented in section IX.C.4.b of this Report.

246. The adjustment to pension plan expense should reflect the actual 1986 contribution. For the reasons stated

in the testimony of Mr. Willis and summarized in section IX.C.4. of this Report, the proper way to calculate the funding requirements of the pension plan is on a present value basis with the funding to occur over the estimated life of the expense. Accordingly, the annual funding requirements are $867,695 (total electric basis), and a corresponding adjustment should be made to rate base.

247. The adjustment to storm damage reserve expense should be based on four years of data, as calculated by GSU, but adjusted to exclude the amounts charged to CWIP.

248. GSU's payments to the public Parties Committee of $500,000 are properly includible in the company's rate case expenses.

249. For the reasons stated in section IX.C.7.e. of this Report, the adjusted premiums for GSU's liability insurance are a reasonable and necessary expense of providing utility service.

250. For the reasons stated in section IX.C.8.e. of this Report, GSU's requested rate case expenses of $6,703,369 are reasonable and necessary even though they are higher than normal. Because the company can be expected to file for another rate increase within a year, the expenses should not be amortized over a two-year period.

251. Although GSU retained a balance of $94,938 in the safety achievement reserve when it terminated the associated safety program, the ratepayers do not have an interest in or claim against that amount of funds. Setting GSU's future rates at a level to transfer the reserve to the ratepayers would require that rates be below the level needed for the company to earn a reasonable return above costs. Accordingly, the adjustments recommended by the staff and the Cities to reduce cost of service by the amount of the reserve are improper and should be rejected.

252. For the reasons stated in section IX.C.10 of this Report, GSU's requested trade association dues expense, as modified by Mr. Bellon, is a reasonable and necessary expense.

253. For the reasons stated in section IX.C.11.d., the Cities' recommendation to exclude the long-term storage cost of generating units from cost of service should be rejected, and the $2,342,250 should be included in costs as a necessary and reasonable expense.

254. For the reasons stated in the summary of the staff and company testimony in section IX.C.12 of this Report, the Edison Plaza lease payment—as adjusted by the staff—is a reasonable and necessary expense, of which 94.82 percent should be charged to operations and maintenance and the remainder capitalized.

255. For the reasons stated in section IX.C.13.d. of this Report, it is not appropriate to adjust operations and maintenance expense as recomemnded by the staff to avoid overrecovery by GSU as a result of CEPCO's reimbursements to GSU for direct costs and overhead charges.

256. The evidence in the record is insufficient to determine whether the $6,929,202 of gains on disposition of assets discussed in section IX.C.14 of this Report were properly recorded by GSU below the line as nonrecurring events that are not part of cost of service. Accordingly, the company should be required to file the information with its next application for a rate change.

257. Because the economy in GSU's service area has recently worsened, the test year expense factor better represents the company's current experience with uncollectible expense than does a factor based on a four-year average. Accordingly, the adjustment recommended by the staff and the Cities should be rejected, and uncollectible expense should be based on the test year expense factor.

258. For the reasons stated in section IX.C.16.d. of this Report, the $860,681 requested by GSU as coal car maintenance reserve accruals is a reasonable and necessary expense, and the Cities' adjustment to the accruals should be rejected.

259. The testimony of the company witnesses summarized in section IX.C.17 of this Report establishes, by a preponderance of the evidence, that GSU does not have sufficient receivables to raise the amount of cash that the Cities witnesses assumed possible and that in the long run, it is less expensive for GSU to borrow funds by using its accounts receivables as collateral than by factoring the receivables. Accordingly, the recommendation of the Cities witnesses to adjust cost of service to reflect the hypothetical cost of raising cash by factoring receivables should be rejected.

260. The preponderance of the evidence, as summarized in section IX.C.18 of this Report, establishes that GSU has not underestimated the savings from its recently implemented meter reading system. Accordingly, the Cities' recommendation to reduce cost of service by $605,188 to take into account extra savings should be rejected.

261. The depreciation expense associated with Nelson Units 1 and 2 should be included in cost of service as a reasonable and necessary expense unless the Commission issues a final order in Docket No. 7174 approving the transfer of the units to a joint venture before it issues a final order in this case.

262. In accordance with the parties' stipulation in Docket No. 6525, depreciation expense of $84,763 related to Big Cajun 2 Unit 3 should be included in cost of service.

263. For the reasons stated in section IX.D.4 of this Report, interim retirements and additions related to GSU's generating units can be most simply and accurately ac-

counted for by using end-of-test-year account balances when the company files for rate increases.

264. For the reasons stated in section IX.D.4 of this Report, the most reasonable estimated net salvage value of GSU's production plant is negative 5 percent.

265. The Cities' recommendation to base the remaining life of common plant facilities at each station on the remaining life of the last-retired generating unit would properly amortize the cost of the facilities over their service life. Accordingly, the Cities' recommendation should be adopted.

266. For the reasons stated in section IX.D.4.e. of this Report, the half-year convention is an appropriate way of determining average service lives and calculating depreciation rates for generating units.

267. As recommended by the Cities, the remaining life of the land rights associated with transmission lines should be based on the endpoint of the transmission equipment survivor curve.

268. The preponderance of the evidence establishes as reasonable the remaining salvage values and depreciation rates proposed by GSU for transmission, distribution, and general plant, with the minor modification recommended by Mr. Rogas.

269. The reasonable and necessary interest on the $14,851,568 of customer deposits held by GSU is $891,094 calculated at the statutory interest rate of 6.0 percent as recommended by the staff.

270. The preponderance of the evidence establishes that GSU incurs taxes other than income taxes with components as set forth in Schedule III of the Order.

271. For the reasons stated in section IX.F.1 of this Report, GSU's pro forma increase of $1,013,867 to its test year payroll taxes is reasonable; however, the increase

must be modified so that payroll taxes related to Nelson Units 1 and 2 are treated in a manner consistent with the treatment of the other items related to those units.

272. For the reasons stated in section IX.F.2 of this Report, GSU's pro forma increase in ad valorem taxes of $2,353,750 is reasonable.

273. On the basis of the staff testimony summarized in section IX.F.3 of this Report, GSU Texas franchise taxes of $5,854,028 are reasonable.

274. The staff's method of calculating the comptroller's audit fee is reasonable and should be adopted; however, the fee should be amortized over a four-year period as recommended by the Cities.

275. The preponderance of the evidence supports the staff-recommended $5,996,211 decrease to GSU's requested amount for revenue-related taxes other than income taxes.

276. The preponderance of the evidence supports the staff's tax calculation procedure to calculate a level of state income taxes.

277. For the reasons stated in section IX.H.6 of this Report, 34 percent is the proper tax rate to calculate GSU's federal income tax expense.

278. The preponderance of the evidence supports the staff-recommended adjustments to GSU's calculation of federal income taxes.

279. The preponderance of the evidence does not support the Cities-recommended adjustment to reflect consolidated tax savings.

280. For the reasons stated in section X of this Report, the staff-recommended adjusted electric sales are reasonable and should be adopted.

281. For the reasons discussed in Section X1.B.1 [sic] [XI.B.1.], the interdepartmental eliminations and re-

classifications proposed by GSU should be approved for purposes of the jurisdictional separations process.

282. For the reasons discussed in Section XI.B.2.a., production and transmission tie line capacity costs and related expenses should be allocated between jurisdictions using the A&E-MDD methodology.

283. As discussed in Section XI.B.2.b., uncollectible expense should be allocated between jurisdictions using a test year ratio rather than the four year average ratio proposed by the Commission staff.

284. Non-tie line transmission facilities should be allocated on a "rolled-in" basis for purposes of the jurisdictional separation study in order to preserve a consistent approach between jurisdictions.

285. For purposes of calculating jurisdictional separation factors for production and transmission tie facilities, both weather adjusted kWh and kW should be used. If weather adjusted kW cannot be calculated using the methodology employed to calculate Schedule O-1-G, then neither kWh or kW should be adjusted for weather.

286. GSU's allocation factor for accumulated provision for depreciation should be used in the jurisdictional cost of service study, for the reasons cited in Section XI.B.2.f. of the Report.

287. For purposes of the jurisdictional cost of service study, the staff's adjustments to PHFU should be allocated using separate transmission tie line and transmission non-tie line allocators rather than using a composite allocator, in order to produce a more equitable allocation between jurisdictions.

288. Consistent with the examiners' rejection of staff witness Bellon's proposed adjustment of O&M expense for CEPCO reimbursements, CEPCO reimbursements should not be considered an expense of the Texas retail jurisdiction.

289. For the reasons stated in Section XI.B.2.i., GSU's original specifically assigned allocation factors for allocation of revenue requirement deferrals and associated deferred taxes should be corrected in order to accurately allocate revenue requirement deferrals and associated deferred taxes, based upon the prudence and rate moderation recommendations adopted by the Commission.

290. For the reasons discussed in Section XI.C.1., and subsections thereof, A&E-MDD should be used to allocate GSU's production and transmission capacity costs between GSU's Texas retail customer classes.

291. For the reasons discussed in Section XI.C.2., non-tie transmission facilities should be allocated between customer classes on a "non-rolled-in" basis.

292. Interruptible demand should be removed from class loads in allocating the expense associated with interruptible credits, for the reasons stated in Section XI.C.3.

293. For the reasons stated in Section XI.C.4., uncollectible accounts expense should be directly assigned to customer classes on the basis of the actual write-off amounts recorded for each class.

294. Texas wholesale demand and energy data should be excluded from the calculation of excess demand at the Texas retail level.

295. Rate comparability between Texas and Louisiana should not be viewed as an appropriate consideration in allocating revenue requirement among Texas retail customer classes, for the reasons cited in Section XI.D.6.

296. Any revenue spread adopted by the Commission should be designed to produce movement of the residential class toward relative unity.

297. Maintenance of appropriate class crossing points should be achieved to the extent possible through rate design rather than through allocation of revenue requirement.

298. For the reasons described in Section XI.D., and subsections thereof, the revenue distribution guidelines listed in Section XI.D.6 are appropriate for use in this docket and should be approved.

299. A separate rate class should not be established for State Agencies, nor should they receive special rate treatment.

300. The residential customer charge should remain at its current level of $7.00 per month, for the reasons stated in Section XII.A.1.

301. GSU's proposal to expand the current residential winter tail block differential from 2¢ to 2.5¢ should be rejected, for the reasons stated in Section CII.A.2. [sic] [XII.A.2.]

302. The Good Cents Rider should be permitted to remain in effect without modification, for the reasons stated in Section XII.A.3.

303. The SGS customer charge should be reduced from $17.70 to $14.00 for the reasons stated in Section XII.B.

304. A summer/winter demand charge differential should be incorporated into the restructured LPS and HLFS rate classes, for the reasons stated in Section XII.C.1.a.

305. The LPS and HLFS voltage level adjustment charges proposed by GSU should be approved for the reasons stated in Section XII.C.1.b.

306. The existing interruptible credits of $4.25 and $2.67 should be applied to the 5 minute and 30 minute notice categories, respectively, for the reasons stated in Section XII.C.2.a.

307. The penalty proposed by GSU for non-compliance with a request to interrupt load should be reduced from four times to two times the firm load kW charge for all kW in excess of firm contract power, for the reasons stated in Section XII.C.2.b.

308. The language contained in the proposed IS rider pertaining to permissible reasons for load interruption should be revised in the manner indicated in Section XII.C.2.c., for the reasons stated in that section.

309. For the reasons stated in Section XII.C.2.d., GSU's proposal to include a 20 percent ratchet in the consolidated IS rider should be approved with the understanding that existing interruptible customers must be permitted a one-time option to revise the level of their contract interruptible load.

310. Future GSU annual system peak load forecasts should be adjusted to exclude coincident interruptible loads subject to 30 minute interruption notice, for the reasons stated in Section XII.C.2.e.

311. The "experimental" designation should not be removed from Schedule IS, nor should any limitations be placed on the number of interruptions which may occur in any given day, for the reasons stated in Section XII.C.2.f.

312. The current facilities charge rate for Schedules LPS and LIS should not be changed, for the reasons stated in Section XII.C.3.

313. Schedule RRI-S should not be adopted, for the reasons set forth in Section XII.D.

314. Except as otherwise indicated in Section XII., the company's proposed rate design is reasonable and should be approved.

315. The fixed fuel factors set forth in Schedule VIII of the Order are reasonable and should be approved.

316. The staff's proposed revisions to GSU's service rates and regulations should be approved with the exception of the proposed revision to Section IV, Sheet No. 1, Sec. 20, which should be rejected for the reasons stated in Section XIII.B. of the Report.

317. Except as otherwise indicated the company's proposed tariff should be approved.

B. *Conclusions of Law*

1. The Commission has jurisdiction and authority in this case, including consideration of the consolidated appeals from the cities listed in Finding of Fact No. 6 and the prudence of GSU with respect to River Bend, pursuant to Section 16, 17(d) and (e), 26, 37, 41, and 43 of PURA.

2. GSU is a public utility as defined by Section 3(c)(1) of PURA.

3. The rate filing package filed by GSU meets the requirements for a statement of intent set forth in Section 43(a) of PURA.

4. The operation of the proposed rate schedule was suspended in accordance with Section 43(d) of PURA.

5. Proper notice was given to all affected persons in compliance with Section 43(a) of PURA.

6. GSU has substantially complied with the requirements for energy efficiency plans set forth in P.U.C. SUBST. R. 23.22.

7. The proceedings in Docket Nos. 857 and 1527 did not meet the standard articulated by the Supreme Court in *U.S. v. Utah Mining and Construction Company*, 384 U.S. 344, 421-22; 86 S.Ct. 1545, 1560 (1966) for application of the doctrine of res judicata to prohibit inquiry into the prudence of the decision to build the River Bend plant.

8. The Commission's decisions in Docket Nos. 857 and 1527 do not preclude the Commission from considering in this docket the prudence of the decision to build the River Bend plant.

9. The argument that once a CCN is granted the Commission may not question a utility's decision to continue

to construct a power plant, even if projected load vanishes, capital costs skyrocket, and alternative methods of serving the public clearly become economically preferable, is inconsistent with the Commission's responsibilities under PURA Sections 2, 38, 41, and 43.

10. The doctrine of res judicata would preclude relitigation of River Bend prudence issues, which were exhaustively litigated in this docket, in any future Commission proceeding.

11. The prudent investment test is embodied in traditional ratemaking principles as expressed through PURA Sections 2, 38, 39, and 41.

12. The Commission has the responsibility and authority to exclude imprudent or wasteful expenditures from invested capital pursuant to PURA Sections 38, 39, and 41.

13. The Commission has the responsibility and authority to disallow imprudently or wastefully incurred expenses pursuant to PURA Sections 38, 39, and 41.

14. The standard of prudence to be applied in establishing the amount of invested capital used and useful in rendering service to the public is as follows:

> the exercise of that judgment and the choosing of one of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives available at the point in time such judgment is exercised or option is chosen.

15. Under PURA Section 40 a utility must prove its conduct to have been prudent when decisions or expenditures are reasonably challenged.

16. The decision to build River Bend was prudent as that term is defined in Conclusion of Law No. 14.

17. The CEPCO buyback agreement was a prudent transaction as that term is defined in Conclusion of Law No. 14.

18. Nine percent of GSU's share of River Bend capital costs, or $274,015,889, should be excluded from GSU's rate base as invested capital not used and useful in rendering service to the public pursuant to PURA Sections 38, 39, and 41.

19. Operating expenses associated with nine percent of the capital costs of River Bend, including the capacity portion of the CEPCO buyback expense, River Bend depreciation expense, and deferred River Bend depreciation expense and return on investment should be excluded from cost of service pursuant to PURA Sections 38, 39, and 41.

20. A mere showing that statistical adjustments to plant costs are unreliable or that plant costs are within the suggested range by statistical confidence intervals is inadequate to meet a utility's burden of proof under PURA Section 40.

21. SFAS 92 sets forth the following criteria, all of which must be met, for revenue deferrals to be capitalized for financial reporting purposes under a phase-in plan:

a. The allowable costs in question shall be deferred pursuant to a formal plant that has been agreed to by the regulator.

b. The plan shall specify the timing of recovery of all allowable costs that will be deferred under the plan.

c. All allowable costs deferred under the plan shall be scheduled for recovery within 10 years of the date when deferrals begin.

d. The percentage increase in rates scheduled under the plan for each future year shall be no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year. That is, the scheduled percentage increase

in year two shall be no greater than the percentage increase granted in year one, the scheduled percentage increase in year three shall be no greater than the scheduled percentage increase in year two, and so forth.

22. The phase-in plan described in Finding of Fact Nos. 190 and 191 and Schedule VII to the Commission's Order meets the requirements of SFAS 92.

23. Pursuant to PURA Sections 38, 39, and 41, GSU should be authorized to defer River Bend-related revenue requirements, capitalize the deferred amounts, and amortize those deferrals over a ten-year period in the manner described in Schedule VII attached to the Commission's Order.

24. As required by Section 41(a) of PURA, the net plant component of GSU's invested capital set forth in Schedule IV of the Order is based upon the original cost of property used by and useful to GSU in providing utility service.

25. The methods and rates of depreciation implicit in Schedules I and IV of the Order are proper and adequate and have been uniformly and consistently applied, as required by Section 27(b) of PURA.

26. To the extent included in invested capital, GSU's generation, transmission, and distribution facilities are safe, adequate, efficient, and reasonable, as required by Section 35(a) of PURA.

27. The overall rate of return and component rates of return allowed by Schedule VI of the Order substantially comply with P.U.C. SUBST. R. 23.21(c)(1).

28. Taking into consideration GSU's quality of management, quality of service, effort to conserve energy and resources, and efficiency of operations, the return set forth in Schedule I of the Order constitutes a reasonable return on GSU's invested capital used and useful in ren-

dering service to the public, as required by Section 39(b) of PURA.

29. The return set forth in Schedule I of the Order will permit GSU a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expenses, as required by Section 39(a) of PURA.

30. Under the circumstances of this case, transferral back to ratepayers of unredeemed, previously accrued safety achievement reserves by reducing future rates would constitute prohibited retroactive ratemaking.

31. A gain from an asset transfer should be distributed between ratepayers and shareholders in accordance with which group had borne the risk of capital loss on the asset.

32. GSU has met the burden of proof imposed by Section 40 of PURA to show that rates producing the total revenue set forth in Schedule I of the Order are just and reasonable.

33. The rates and rate design implied by the customer-class revenue requirements in Schedule V of the Order are just and reasonable and are not unreasonably preferential, prejudicial, or discriminatory within the meaning of Section 38 of PURA.

34. As required by Section 45 of PURA, the implied rates and rate design do not grant an unreasonable preference or advantage to any customer within a classification, subject any customer within a classification to an unreasonable prejudice or disadvantage, or establish unreasonable differences as to rates or service between localities or between classes of service.

35. The rates approved by the Commission in this case are to be effective only for customers in areas within the Commission's original jurisdiction and in the cities from which appeals were consolidated with this case.

36. There exists no Constitutional or statutory requirement that rates paid for utility service by state agencies must be fixed at a level equal to cost, assuming a relative rate of return at unity, as determined by a class cost of service study.

37. The rates implied by Schedules I-VI of the Order are just and reasonable and otherwise comply with the rate-making mandates of Article VI of PURA and should be approved.

Respectfully submitted,

/s/ Henry D. Card
HENRY D. CARD
Administrative Law Judge

/s/ Mark W. Smith
MARK W. SMITH
Administrative Law Judge

/s/ Charles J. Smaistrla
CHARLES J. SMAISTRLA
Hearings Examiner

APPROVED on this the 7th day of December 1987.

/s/ Mary Ross McDonald for
PHILLIP A. HOLDER
Director of Hearings

APPENDIX I

TRANSCRIPT OF PROCEEDINGS
BEFORE THE
PUBLIC UTILITY COMMISSION OF TEXAS
AUSTIN, TEXAS

Docket No. 7195

IN THE MATTER OF THE PETITION OF GULF STATES UTILITIES COMPANY FOR AUTHORITY TO CHANGE RATES

Docket No. 6755

IN THE MATTER OF THE INQUIRY OF THE PUBLIC UTILITY COMMISSION OF TEXAS INTO THE PRUDENCE AND EFFICIENCY OF THE PLANNING AND MANAGEMENT OF THE RIVER BEND NUCLEAR GENERATING STATION

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*FINAL ORDER MEETING**

[February 23, March 10, March 15, 1988]

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[2239] CHAIRMAN THOMAS: I see.

Well, then what I would propose is to take up and decide the issue of prudence. Is that acceptable?

COMMISSIONER CAMPBELL: Fine.

CHAIRMAN THOMAS: Okay.

With your indulgence, I would like to suggest some alternative ways of viewing the prudence question. Are you interested in hearing some of those?

[2240] COMMISSIONER GREYTOK: Why not?

CHAIRMAN THOMAS: Why not.

COMMISSIONER CAMPBELL: Be glad to.

CHAIRMAN THOMAS: You would be glad to?

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* [Excerpts]

COMMISSIONER CAMPBELL: Are they the same that you set forth the other day?

CHAIRMAN THOMAS: Well I—

COMMISSIONER CAMPBELL: Or did you come up with new ones?

CHAIRMAN THOMAS: Always an improvement.

I put these down because it's a little bit difficult sometimes especially in numbers, and as you see I've handed you a list. I've got eight potential alternatives. There are six of them which I would just like to run over quickly. If there are any of those which you would like more discussion of, I would be happy to do so since each of them is outlined in detail in terms of attempting to outline the assumptions.

As I've said all along, I believe that a number has emerged out of this case as a consensus which is somewhere in the 8 to $900 million range in terms of a reduction to rate base. There are alternative ways of treating that reduction to rate base: some in terms of disallowance, some in terms of either inventorying or holding a piece of plant in abeyance.

[2241] The plan which I believe is the best for all involved is one which I've discussed before. It is a straight disallowance based upon the second alternative Staff model. This is the Staff model as suggested by Dr. Perl. In effect, it is a 15 percent disallowance which is—results in a disallowance somewhere in the range of about 450 million.

To that, I would add an inventory plan based upon the Cities' testimony. What you do is you recalculate the average cost per kilowatt. You take the excess capacity figure as recommended by Mr. Pous, a City witness; that adds up to an inventory figure somewhere also in the range of 450 million. Together, the inventory plus the disallowance would reduce rate base by 955 million.

Of all the plans, that is the one which I believe is preferable. Knowing, based upon some of your previous comments, your apparent reluctance at that time with regression models, I tried some alternative approaches which get somewhere in the same neighborhood.

A second alternative approach would be to take the Examiner's Definitive Cost Estimate, add to that a factor due to regulatory change. We have a couple of alternative regulatory change factors in the record. The highest and the one I'm most comfortable with is the 46 percent figure which was actually brought forth by the Company. [2242] I believe that 46 percent, if you are not having other sorts of adjustments, is a reasonable figure which is fairly well documented in the record as, you know, either being reasonable or in some cases as being conservative. If you use the Examiner's Definitive Cost Estimate with the 46 percent increase due to regulatory change, then it comes up to a disallowance of 854 million.

A third alternative is to begin with the 1979 Definitive Cost Estimate. You have to begin with that—it's a lower number—because the Examiners already had some of these other factors built into their number. You begin with the 1979 Definitive Cost Estimate and then you add back the percentage of cost changes which the OKA survey found justifiable. I think if you go back and look at the way the OKA, the Public Parties witnesses did, they took a sample of the change orders, went through those to see if they agreed with the way the Company had classified those and to see if they agreed whether or not they were cost justified.

From that, we derived a percentage based upon their sample of the change orders which they found justifiable and then applied that to the amount of the increase over and above the 1979 figure. That analysis results in a disallowance of 737 million.

There are, you know, endless variations. You can take the 1979 figure; you can add back in inflation; there [2243] are a couple of ways to calculate inflation; one is the Stone & Webster inflation calculation, a second as you will see in Alternative No. 5 is an inflation factor calculated using the Handy-Whitman Nuclear Construction Index.

You can also add back in—well, essentially that is, you take the 1979 cost estimate and you say obviously we had

inflation so what are the effects of inflation. If you calculate it using the Stone & Webster, it's a $659 million disallowance; if you calculate it using the Handy-Whitman index, it's a 502 disallowance.

Let me end with this—the last alternative I proposed to discuss, which is one which was laid out by Staff.

Mr. Hanger laid out an alternative which is based in theory upon the Staff's finding that a third of the costs were not proven. And what he had proposed was a combination of a straight disallowance based upon the regression model which the Examiner used with the remainder being held in abeyance. It's based around a 33 percent figure. It would result in a reduction to rate base of 755 million.

So, the advantage to this plan is that it is based upon an abeyance which would allow the Company to come back in and attempt to prove those costs at a later time, as opposed to the theory being one of inventory. Of the two—of the plans I've discussed, my preference is for the first [2244] plan which is the $955 million reduction to rate base. My second preference is for the one discussed by Staff, which is the 33 percent combination of ebeyance and disallowance which results in a reduction of 755 million.

COMMISSIONER GREYTOK: Mr. Chairman, I think that we've had a discussion previous to this about the regression analysis model.

I think that there are lies, damn lies, in statistics and that one probably falls, in my view, very firmly into the latter category.

In going down through the various proposals that you have outlined, there is only one that I can support at all and that one not enthusiastically and that one is the Definitive Cost Estimate plus OKA.

There is another option and it's one that we have brought forward here before, and that is the option of allowing what is appropriate and proper and that is what has been proven up. As Commissioner Campbell has said

so many times, we have to base this on the law and what has been proven.

In that instance, the share of GSU's share by taking 2.273 billion and multiplying it by 70 to get their share would be 1.5911 and that would be their share of the reasonable cost. Their share of the unexplained cost is 1.4 billion.

[2245] My preference would be to give them what is their reasonable share and when I say give, I think that that is a poor word, really. That is what is obviously appropriate and properly theirs. The other portion I would not like to apply disallowance. I would like to see us consider holding that to one side, holding it open and allowing the Company to come forward if they can at some point in the future and prove that up. I think that that's the least destructive method.

I would certainly hope that they could do a better job than has been done given the opportunity to come back. I also would hope that it would not result in something that would equal, say, even under the regression analysis of $459 million disallowance, which is a lot of money. The OKA is a $737 million disallowance. Once again, that is a very heavy hit.

If the Company can prove up the 1.4 or anywhere near that or anything better than 737 million or 459 million, I would like to give them the opportunity to do it. It isn't with any desire to be punitive in this matter whatsoever that I make this proposal. It's with the idea that the ratepayers certainly would be the beneficiary of a company that is in good solid financial condition and the Company would benefit from the standpoint that they can, through this method, certainly obtain what monies are justifiably and properly theirs.

[2246] As all of you in the room know, I had some concerns about the prudence issue. But the main concerns that I had dealt with the restart and I think that I put those to bed based on some questions that I asked here in the room of the attorneys and some reading that I did on

some case law in that area. I have a great deal of difficulty in determining that a past Commission granting of a CCN or the Legislature in its grandfathering "made a mistake."

I don't find that that is something that I deal with well from the standpoint of imposing my judgment over theirs. So I don't want to go back to that. I think with that in mind, we have to move forward to the construction issues and that's where we have the question and so, my suggestion here is that we look at holding River Bend cost portion of it, GSU's unexplained increase to one side; not to disallow it but not to place it in rate base at this time in this rate case.

COMMISSIONER CAMPBELL: Well, as I said earlier, I make my decisions as I understand the law. And as I understand the law, Gulf States has the burden of proof to prove by a preponderance of the evidence that their cost overruns were reasonable and necessary and incurred through efficient management.

I do think that this is an important issue and I think what we do in this case is going to set a precedent for [2247] how we deal with our future cases. I have been very outspoken on wanting us to be fair and reasonable. I certainly have never had a reputation as being a utility basher.

In fact, I would call to everyone's attention, I was the one who wrote a very vigorous dissent on this Commission's finding the Southern contracts imprudent. But I personally think the Examiners have done a magnificent job, an outstanding job in their logic, in their reasoning on this prudency issue except when they—as they have—as the Examiner in that portion—in this portion has admitted he reluctantly had to move to regression analysis.

I cannot support regression analysis. I think that as the Company itself argued, it is too subjective. It is too subject to playing with figures and manipulation. I think it is suitable to show that there are unexplained costs that need to be—to raise the question of the prudency of

the expenditures. But, you know, I think when we look at the Company's rate case expense, then I think that that should tell us that we should not be using regression analysis.

So I simply cannot go with the regression analysis. But I think it was at my suggestion that we did hire some outside consultants and our engineering firm that we hired specifically to look at the construction costs, concluded that neither Gulf States nor OKA, the Public Parties [2248] Committee, had adequately supported its contentions regarding the amount of cost increases attributable to regulatory changes.

In fact, they said that there was not sufficient evidence to enable us to make a finding of either prudence or imprudence and I agree with that. I think the Examiners have pointed out that merely because there has been a regulatory change does not mean that the Company has spent the money wisely or prudently in meeting that regulatory change. And I would use as an analogy what all of us observed happening here yesterday.

It was obvious that the Company had to put on Mr. Johnson to discuss the rate case expense. But I would say it certainly was not necessary for them to bring a young lady here at 145 or more per hour to put him on when they have a very competent in-house attorney that could have done the job. And I think that is simply true, as the Examiner's pointed out in his report, merely because there was a regulatory change gives us absolutely no knowledge as to the way that the Company dealt with that regulatory change as to whether it was prudent or not.

It seems to me that the Examiners have supported their finding that a definitive cost estimate would have been 2.273 billion. I support that, but as to any increase over and above that, I would find that the Company has simply [2249] failed in their burden of proof. I would be willing to certainly say that that finding is not res judicata and that, you know, I would certainly be most

receptive to entertaining a motion for rehearing, and allow the Company the opportunity to prove up the exact amount that is reasonable and prudent.

At the same time, because the Company has had every opportunity to prove that number up, I think that should they request another opportunity to prove it up, the burden of those costs, of those litigation costs, should be theirs and should not be borne by any ratepayers.

COMMISSIONER GREYTOK: Mr. Chairman, let me add one more comment.

I think it's important, reflecting on something that Dr. Draper said that they need help in the first year, that in looking at the justifiable cost of GSU's share, or GSU's justifiable or reasonable share, that we should look at whether or not we need a phase-in plan during the first year, should we go in that direction or whether or not it would be possible to allow the Company a fairly firm step into that number so that they would essentially be stable financially at that point.

COMMISSIONER CAMPBELL: Yeah, I could certainly support that. I think, as I said, that the phase-in plan—the Staff's phase-in plan certainly took that into consideration on the cash flow issue and I think [2250] with some modification perhaps to that plan, their cash flow problem can be handled, but, you know, as much as I have sympathy with the Company's plight, they had ample opportunity. They spent money on top of money trying to prove their case.

I did find it most interesting as did the Examiner that, though they could pay millions upon millions for lawyers and other consultants, they could only find $300,000 to attempt to prove up the reasonableness of their overrun in construction costs.

CHAIRMAN THOMAS: All right.

It appears that we have two possibilities here narrowed down.

Commisssioner Greytok, you said your preference was for allowing 1.591 which was the Definitive Cost Esti-

mate. As I understand it, that is the same figure that you used, Commissioner Campbell.

COMMISSIONER CAMPBELL: That's right. 2.273, I believe, was the—

CHAIRMAN THOMAS: Times 70 percent, comes up to the same thing.

COMMISSIONER CAMPBELL: Right. Except I think it is very critical that we understand when the Company has failed to prove up the reasonableness of the costs on River Bend, just as the Examiners dealt with that in the CEPCO [2251] buyback, we must deal with it in the same manner. You can't allow costs in a CEPCO buyback that haven't been found to be reasonable yet.

CHAIRMAN THOMAS: Okay. What I was attempting to establish is that you used different numbers but I think you're both talking about the same number. So that's one alternative.

Commissioner Greytok, you said you had not completely closed the door on my Alternative No. 3, which was the 1979 Definitive Cost Estimate plus the percentage of costs which OKA found justifiable in their sample.

COMMISSIONER CAMPBELL: I would like to remind before we vote on that, that our own engineering firm that we hired to be fair and impartial, specifically found that neither the Company nor OKA had adequately supported its contenions regarding the amount of cost increases attributable to regulatory changes.

I think if you read the Examiners' Report clearly, and closely, it is clear that, you know, the purpose of OKA was not to try to find a definitive amount of prudence in the construction. It was merely to show that there were problems with the Company's presentation and as—again, our impartial witness stated that neither Gulf States nor any of the parties offered sufficient evidence to enable us to make that kind of decision. Plus, I go back and would use my [2252] analogy of how they dealt with putting Mr. Johnson on. Merely—even if you found,

as the Examiner noted in his discussion, even if you found a particular number of regulatory changes, you do not know that the cost that grew out of those changes were prudently incurred or were incurred in the most efficient and necessary and reasonable manner.

CHAIRMAN THOMAS: Well, I guess the answer—your comments—we known what the cost—what the plant was supposed to have cost in 1979. We know what it was finished for. There is a big difference.

COMMISSIONER CAMPBELL: And that's right. And I agree with you that there is probably some that is regulatory change and some inflation, but there is also a little factor in the law called arbitrary and capricious and the case law has held, unless you can find a logical nexus between the facts and your decision, you're acting arbitrarily and capricious.

Now, if I just choose a number and there is no logical nexus between that number and the facts in the record, then I am being arbtirary and capricious. And I don't know. I think that there is something. I hope the Company can prove ultimately its case. But until they do so, any number I hang my hat on now, I am doing it in an arbitrary and capricious manner.

CHAIRMAN THOMAS: All right.

[2253] I think the key difference here is between making a decision, more final decision in the case, versus a remand. I think—

COMMISSIONER CAMPBELL: And I'm not saying there has to be a remand. I want you to understand that. I think that choice is the Company's.

CHAIRMAN THOMAS: I need to get to finish that thought. I don't think quite as fast as you do. Okay?

COMMISSIONER CAMPBELL: Okay.

CHAIRMAN THOMAS: The key difference then is whether you remand and see if they can prove up the difference since—if you don't feel that they have made it, versus finding our best estimate of what the difference ought to be.

The theory behind No. 3 is you take the original cost estimate and then you take the adversary witness. I went back and looked at the sampling procedure that OKA used. It appeared to me to be sustainable. I looked at their cost classification. Roughly, they found 59 percent of the change orders they examined to be justifiable. And, you know, frankly, I think that number could have been higher, could have been lower, but the fact that you're applying the work of the adversary witness, I think, gives you a sustainable number.

So, I think the disagreement here is not so much on [2254] what that number is versus whether or not you feel it's important to make a final decision in the case versus whether or not we ought to go back and remand and I think that is an open question which is best for the ratepayer and which is best for the Company.

COMMISSIONER CAMPBELL: Well, mine is again more a matter of law, Commissioner Thomas.

I think that, you know, again, the Company has the burden of proof. I didn't write the law; the Legislature wrote the law, but I certainly took an oath of office to follow the law.

And again, I would point out the two instances; one, that our own impartial construction expert said that neither OKA nor the Company regulatory—those changes supported its contention regarding the amount of cost increases attributable to regulatory changes and, again, I would point out the Examiner in my opinion was absolutely on target when he said even if you had a regulatory change, there is nothing in the record to show that the Company acted in a prudent manner in dealing with that regulatory change to quantify the actual cost that should be allowed.

CHAIRMAN THOMAS: Okay.

Well, I guess I viewed the results of our own impartial witness slightly differently. I think our own witness said, "Boy, this is a complicated case and for [2255] the"—

COMMISSIONER CAMPBELL: I think that was the—

CHAIRMAN THOMAS: —"amount of time"—

COMMISSIONER CAMPBELL: I think that was the economic witness, I believe, rather than the construction engineer.

CHAIRMAN THOMAS: Well, I think both of them did it the same way and then said, "I really don't think that either side has done enough to prove," which was obviously one of the things they said and some of the other things they said weren't, but if you had to come up with a standard then here's a way to do it with regression models or here's a way to do it with a broad-based approach and take 33 percent—I mean, they gave us some options.

COMMISSIONER CAMPBELL: Except those again —both of those suggestions came from your economists and not from your construction engineer.

CHAIRMAN THOMAS: One was more impartial than the other?

COMMISSIONER CAMPBELL: Well, I think—no, I think that the construction engineer is the expert on construction cost. That's why we hired him.

CHAIRMAN THOMAS: It's your turn.

COMMISSIONER GREYTOK: I think at this point, [2256] that we should just go ahead and close the door on the OKA. If I'm understanding Commissioner Campbell correctly, she's indicating that she can go with the numbers or has already had the numbers that I had, so has arrived at the same conclusion apparently. So I think that I would like to indicate that I am comfortable, more comfortable with—and actually is the only thing I feel my integrity will support, is to appropriately and properly give the Company what is reasonably and justifiably theirs and what is not, hold it to one side and I think that is the best opportunity for the Company, also.

The OKA disallowance is, as I said, 737 million from your number. And although it means that there would

have to be a limited remand, I think that that would be my preference.

CHAIRMAN THOMAS: Okay.

There are a couple of—obviously, I think there are two votes that go that direction.

There are a couple of details which we need to discuss in terms of the way you've described it; setting it aside, giving them an opportunity to prove it. The main—these are essentially—are cash flow details.

Do you allow—obviously you don't allow a return on investment and that's the heart of the matter we are going to. Do you allow operations and maintenance expenses and do [2257] you allow depreciation on that part of the plant in the meantime?

COMMISSIONER CAMPBELL: Certainly, I think that you allow operation and maintenance expenses on the plant, because that has nothing to do with your disallowance.

I don't think you can allow depreciation expense on expense if no one has justified should have ever been incurred. So again, I think—you know, the treatment of the non-proven expenses should be dealt with exactly as the Examiners dealt with them in the report on they amount found not to have been proven up.

As I said, it should certainly flow through to the CEPCO buyback. It should flow through to your depreciation. It should flow through to your deferred—your deferrals on depreciation, AFUDC and those items. I don't think—if you haven't proven it in one place, you certainly haven't proven it anywhere else.

CHAIRMAN THOMAS: Obviously, you can take either approach. The question is whether or not they survive to the end to which they can actually prove it. And, you know, one way to do that, if you're just concerned about cash flow, is to, in the meantime, allow operations, maintenance and depreciation.

COMMISSIONER CAMPBELL: I certainly think they get their operation and maintenance expenses. I

don't think [2258] they get their depreciation or it included in the CEPCO buyback. I think the cash flow issue gets taken care of in your phase-in plan.

COMMISSIONER GREYTOK: I can support that.

CHAIRMAN THOMAS: Okay.

Then as I understand the decision of the Commission on the prudence issue, is to—

COMMISSIONER CAMPBELL: I think there is a related issue to River Bend, if we want to get through with River Bend—

CHAIMAN THOMAS: Okay. Certainly.

COMMISSIONER CAMPBELL: —that you haven't mentioned that I certainly had on the list and that's the capitalized advertising expense that was included in part of the cost of River Bend. And my recommendation would be to disallow those capitalized advertising expense. I think that advertising expense weren't shown to be a necessary expense that should be capitalized and that that's just a normal expense that is expensed in the test year and, therefore, I would disallow the capitalized River Bend advertising expense.

CHAIRMAN THOMAS: But you would not put it in the test year. Is that correct?

COMMISSIONER CAMPBELL: If they were not incurred, as I understand it in the test year; these are past [2259] expenses that the Commission in the past has disallowed and they just capitalized them.

CHAIRMAN THOMAS: You didn't believe the argument that advertising expense such as safety plans and so on is not a normal part of building a nuclear plant?

COMMISSIONER CAMPBELL: They could not and they admitted that that was only a very minor portion and they did not prove that and again, since there is no way to separate out what might have properly been capitalized and what could not, it seems to me you have to disallow it all.

CHAIRMAN THOMAS: Why don't, then, you wrap those—the capitalized advertising expense and your ap-

proach on the larger prudence issue into something which we can take a vote on.

COMMISSIONER CAMPBELL: Well, I would go with Commissioner Greytok's recommendation that we allow the 2.273 billion Definitive Cost Estimate found by the Examiners, that portion of it attributable to Gulf States, and that portion attributable to the CEPCO buy-back, as the proven expenses for River Bend with the disallowance of the capitalized River Bend advertising expense, and that we find that those other expenses that are being—not included at this time because of the failure of proof by Gulf States as to showing the reasonableness and necessity.

CHAIRMAN THOMAS: Okay.

[2260] Do you want to indicate your intention or just willingness to reconsider?

COMMISSIONER CAMPBELL: Well, I think that again is certainly up to the Company and the Company can either do it in asking for a motion for rehearing—I think, both Commissioner Greytok and I have indicated our willingness to entertain a motion for rehearing on that issue or if they desire to just file a new rate case; you know, that choice is really theirs.

CHAIRMAN THOMAS: Okay.

Do you want to specify that they are allowed to recover operations and maintenance costs in the interim?

COMMISSIONER CAMPBELL: Yes, very definitely. Operation and maintenance cost, but it would be exactly as the Examiners found, but certainly the depreciation and the deferral of depreciation would not be included.

CHAIRMAN THOMAS: Okay. Is that—

COMMISSIONER GREYTOK: I can concur with that letting the record firmly show that GSU's share of the reasonable cost is 1.5911 which is the 70 percent share of 2.273 billion.

CHAIRMAN THOMAS: Okay.

And I will dissent on that.

Let's take the cost of capital issue next.

* * * *

[3126] COMMISSIONER CAMPBELL: . . . . You should not try to retry issues. This Commission has specifically stated by [3127] majority vote that that amount of River Bend that they didn't prove up was held in abeyance with them having an opportunity to retry it. There is to be no write-off as a loss of that amount.

Now, we are all parties in this case, seem to be trying to push further than what the Commission asked. It is not, it is not in the public interest. Those parties who are being funded by taxpayer and ratepayer dollars, through your actions, have driven out those people who are having to foot their own bill. And we cannot tolerate that as a Commission.

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[3318] COMMISSIONER GREYTOK: Let's clarify something, though, right now. We have a portion of that plant held in abeyance, but we do not have a disallowed portion of that plant.

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[3516] COMMISSIONER GREYTOK: Ms. Casstevens, let me pose this: You do understand that we have not disallowed yet the portion of River Bend that is held in abeyance?

MS. CASSTEVENS: And that is all the more reason to reflect the interest and, for that matter, perhaps the depreciation on River Bend in the income tax allowance.

COMMISSIONER GREYTOK: Well, I have some concerns about how we apply that, and that's part of where my [3517] concern lies with what we're looking at here.

And I think that I'm going to go back and read your replies on this again because I did not find that strong a case presented at the time. I know that Commissioner Campbell picked up on it, but it was not so strong that it was an urgent matter with y'all at that mark. And the decision had already been rendered by the Court.

MS. CASSTEVENS: As I recall, I attached the decision to my exceptions to the Examiner.

COMMISSIONER GREYTOK: I will go back and look at it again, but I am concerned that we not get into the record the statement that the, quote, disallowed portion of River Bend. It is held in abeyance, and we need to understand that in what we're doing here.

MS. CASSTEVENS: Okay. But, you know, the amount—still the issue is—

COMMISSIONER GREYTOK: Because, otherwise, it looks as though we have already made the decision.

COMMISSIONER CAMPBELL: Well, we've made the decision that they haven't proven it at this point in time.

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APPENDIX J

IN THE SUPREME COURT OF TEXAS

No. C-9287

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES, OFFICE OF PUBLIC UTILITY COUNSEL and THE CITY OF BRIDGE CITY, *et al.*,
Petitioners,

v.

PUBLIC UTILITY COMMISSION OF TEXAS and GULF STATES UTILITIES COMPANY,
Respondents.

[EXCERPTS OF]
GULF STATES UTILITIES COMPANY'S BRIEF IN RESPONSE TO APPLICATION FOR WRIT OF ERROR

November 22, 1989

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A. Under the Circumstances of This Case, Neither *Res Judicata* Nor Collateral Estoppel Act as a Bar to Consideration by the Commission of the Additional $1.4 Billion in River Bend Investment.

The logical beginning for any inquiry related to the applicability of the doctrines of *res judicata* or collateral estoppel is the order or judgment from which the res or the matters allegedly disposed of originate. Only matters that have been finally adjudicated and determined can be deemed conclusive of the rights of the parties in subsequent actions. *See United States v. Utah Construction & Mining Co.*, 384 U.S. 394, 86 S.Ct. 1545, 16 L.Ed.2d 642 (1966); *Van Dyke v. Boswell, O'Toole, Davis & Pickering*, 697 S.W.2d 381, 384 (Tex. 1985). In this case, the inquiry must therefore begin with an analysis of the Commission's Final Order, focusing on what the Commission actually decided, and what was plainly not decided.

The Court of Appeals, in considering the validity of Petitioner's arguments, determined that the Docket No. 7195 Order is susceptible of but one sensible interpretation. The Commission, having decided that the restart decision was prudent, ruled that the plant's reasonably estimated cost at the time of the restart, $2.273 billion, was a prudent cost. However, the Commission was clear and explicit that it was making no decision as to the prudence or imprudence of the $1.4 billion in costs incurred over the estimated level of the appropriate estimate. On this issue, the Commission's only *decision* was that it would defer consideration of the prudence or imprudence of this cost until the Company presented further evidence reconciling and explaining that cost growth. By definition, the preclusive doctrines of *res judicata* and collateral estoppel are inapplicable to this decision by the Commission.

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APPENDIX K

IN THE COURT OF APPEALS FOR THE THIRD SUPREME JUDICIAL DISTRICT OF TEXAS AT AUSTIN, TRAVIS COUNTY, TEXAS

No. 3-89-167-CV

PUBLIC UTILITY COMMISSION OF TEXAS and GULF STATES UTILITIES COMPANY,
Appellants,

v.

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES, *et al.*,
Appellees.

[EXCERPTS OF] BRIEF OF APPELLANT, GULF STATES UTILITIES COMPANY

August 18, 1989

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[T]he trial court's conclusion, that the Commission's findings in Docket No. 7195 preclude a subsequent examination of costs in excess of those included in rates at this time, fundamentally misapplies the legal concepts of *res judicata* and collateral estoppel. Before the preclusive effects of *res judicata* or collateral estoppel apply, there must first be an actual resolution of the disputed facts after adequate opportunity for litigation. *See United States v. Utah Construction & Mining Co.*, 384 U.S. 394; 86 S.Ct. 1545; 16 L.Ed.2d 642 (1966).[6] In *Utah Construction*, the Supreme Court stated:

> When an administrative agency is acting in a judicial capacity *and resolves disputed issues of fact properly before it* which the parties have had an adequate opportunity to litigate, the courts have not hesitated to apply *res judicata* to enforce repose.

Id. at 384 U.S. 422, 86 S.Ct. 1560 (emphasis added).

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[6] Although *Utah Construction* and other cases cited by Appellees addressed the preclusive effect of administrative proceedings on subsequent *judicial actions*, this case presents the slightly different question of whether subsequent *administrative proceedings* are barred by prior administrative proceedings. Nevertheless, it is clear that preclusive effect can only be given in this situation if the parties had a full and fair opportunity to litigate the matters involved and the prior administrative proceeding culminated in a definitive resolution of the matter to be accorded collateral estoppel effect. *Yashon v. Hunt*, 825 F.2d 1016, 1021 (6th Cir. 1987) *cert. denied*, —— U.S. ——, 108 S.Ct. 2015 (1988). Neither of these requirements are satisfied in this case.

APPENDIX L

IN THE 250TH JUDICIAL DISTRICT COURT
OF TRAVIS COUNTY, TEXAS

No. 447,502

GULF STATES UTILITIES COMPANY, *et al.*,
Plaintiffs,

v.

THE PUBLIC UTILITY COMMISSION OF TEXAS, *et al.*,
Defendants.

[EXCERPTS OF]
BRIEF OF GULF STATES UTILITIES COMPANY
ON RES JUDICATA AND COLLATERAL
ESTOPPEL ISSUES

April 26, 1989

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B. The Commission's Final Order in Docket No. 7195 Cannot Be Given *Res Judicata* or Collateral Estoppel Effect As to the Overall Prudence of the Capital Expenditures of River Bend Because the Commission Plainly Did Not Decide That Issue.

Even if the foregoing analysis of the Commission's statutory authority to adopt the approach embodied in Conclusion of Law 10 were rejected, it would be error to give preclusive effect to the Commission's Order in Docket No. 7195. Before the preclusive effects of *res judicata* or collateral estoppel apply, there must first be an actual resolution of the disputed facts after adequate opportunity for litigation. *See United States v. Utah Construction & Mining Co.*, 384 U.S. 394, 86 S.Ct. 1545, 16 L.Ed. 2d. 642 (1966); *Tarter v. Metropolitan Savings & Loan Association*, 744 S.W.2d 926, 927-28 (Tex. 1988); *Bonniwell v. Beech Aircraft Corp.*, 663 S.W.2d 816, 818 (Tex. 1984). In this case, the prudence or imprudence of the cost of River Bend above the 1979 Definitive Cost Estimate as adjusted by the Commission has not been resolved. The Commission has expressly so stated in Conclusion of Law 10. The Commission throughout the Final Order Meetings in Docket No. 7195 and in formulating Conclusion of Law No. 10, took pains to make it clear that rate recognition of the balance of River Bend's construction costs over and above the adjusted 1979 cost estimate was not being decided, so as to remove any doubts as to possible preclusion of this issue. *See, e.g.*, Final Order Meeting Tr. at 2249 (Commissioner Campbell) ("I would be willing to certainly say that that finding is not *res judicata*. . . I would certainly be most receptive to entertaining a motion for rehearing, and allow the Company the opportunity to prove up the exact amount that is reasonable and prudent."); *compare* Proposed Conclusion of Law No. 10, Examiners Rpt. at 391, *with* Conclusion of Law No. 10, Final Order at 37. By holding in abeyance the balance of River Bend's construc-

tion costs, the Commission expressly declined to give to this issue the "final resolution" necessary before the doctrines of *res judicata* or collateral estoppel may be used to preclude consideration of these matters.

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APPENDIX M

IN THE SUPREME COURT OF TEXAS

No. C-9287

COALITION OF CITIES FOR AFFORDABLE UTILITY RATES, OFFICE OF PUBLIC UTILITY COUNSEL and THE CITY OF BRIDGE CITY, *et al.*,
Petitioners,

v.

PUBLIC UTILITY COMMISSION OF TEXAS and GULF STATES UTILITIES COMPANY,
Respondents.

From Travis County; Third District of Texas, Cause No. 3-89-167-CV

[EXCERPTS FROM]
MOTION FOR REHEARING OF
GULF STATES UTILITIES COMPANY

September 27, 1990

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REHEARING POINT OF ERROR ONE

THE COURT'S DECISION PRODUCES AN "END RESULT" THAT IS IN VIOLATION OF THE UNITED STATES AND TEXAS CONSTITUTIONS.

A. *The Constitutional Standard*

The Fifth and Fourteenth Amendments to the United States Constitution protect utilities from being limited to a charge for their property serving the public which is so "unjust" as to be confiscatory. *See Duquesne Light Co. v. Barasch*, 109 S.Ct. 609, 615 (1989); *Federal Power Commission v. Texaco, Inc.*, 417 U.S. 380, 391-92, 94 S.Ct. 2315, 2392, 41 L.Ed.2d 141 (1974); *Federal Power Commission v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585, 62 S.Ct. 736, 742, 86 L.Ed. 1037 (1942). Similarly, Article I, Section 17 of our Texas Constitution recognizes that the property of a public utility, though devoted to the public service, is still private property and neither the corpus of that property nor its benefits can be "applied to the public use without adequate compensation." Tex. Const. art. I, Section 17; *See Railroad Commission v. Houston Natural Gas Corp.*, 155 Tex. 502, 289 S.W.2d 559, 563 (1956); *Lone Star Gas Co. v. State*, 137 Tex. 279, 153 S.W.2d 681, 696 (1941); *Harris County Flood Control District v. Shell Pipeline Corp.*, 578 S.W.2d 495 (Tex. Civ. App.—Houston [1st Dist.]), *aff'd*, 591 S.W.2d 798 (Tex. 1979). To ensure that "just compensation" is achieved, the agency regulating the utility is charged, as a Constitutional imprative [sic], to balance the interest of investors and consumers. *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 519, 64 S.Ct. 281 (1944). As is shown below, the Court's September 12, 1990 decision would deny Gulf States this balancing, in violation of its Fifth and Fourteenth Amendment rights.

B. The Court Has Violated These Constitutional Standards by Abrogating the Commission's Attempt to Balance Consumer and Investor Interests.

The Commission's Order in Docket No. 7195 reflects its attempt to balance consumer and investor interests in determining the amount of rate base recognition to be given to Gulf States' investment in River Bend. The Commission had to consider many factors to arrive at a "just and reasonable rate." For example, Gulf States is obligated by statute to supply adequate electric power to its service area. *See* PURA Section 35. This statutory obligation to serve includes the provision of sufficient amounts of electricity to meet whatever demand is needed, an obligation commonly found in public utility statutes nationwide. Gulf States undertook construction of River Bend in order to provide sufficient electricity to meet that obligation. Because of economic and regulatory changes that affected the nuclear industry in general, the overall cost of River Bend escalated dramatically. By the time of the hearings in Docket No. 7195, Gulf States was in an extraordinarily precarious financial situation. As the quid pro quo for Gulf States' efforts and large expenditures made to provide electric service to the public, the Commission recognized that Gulf States was entitled to recover a return of, and a return on, its prudently invested capital. *See* Ex. Rpt. at 18-19; COL 14.

In the *Hope* case, the United States Supreme Court explained what constitutes a minimum, constitutionally-compensatory rate of return:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Id. at 603 (omitting citations); *accord, Permian Basin Area Rate Cases*, 390 U.S. 747, 792, 88 S.Ct. 1344, 1373, 20 L.Ed.2d 312 (1968); *see also Duquesne*, 109 S.Ct. at 618; *Bluefield Water Works v. West Virginia Public Service Commission*, 262 U.S. 679, 692-93, 43 S.Ct. 675, 679 (1923). *Hope* established that in determining whether a rate order meets this Constitutional standard, one looks at the end result—i.e., the total effect of the rate order. 320 U.S. at 602-603; *accord, Duquesne* 109 S.Ct. at 617.

The Commission in Docket No. 7195 was faced for the first time with passing on to Texas ratepayers the enormous cost of a nuclear power plant. The Commission determined that the consumers had a valid interest in receiving regulatory scrutiny of every dollar over and above a 1979 cost estimate. This was certainly a fundamental factor in considering how much of the River Bend investment the Commission would allow in rate base.

The Commission considered these pertinent factors and many others which were developed in the massive record. The Commission attempted to strike a careful balance which is reflected in the Docket No. 7195 Order. The Commission permitted Gulf States to recover $2.273 billion of the Company's investment in River Bend *at this time*, and the Commission allowed for a compromise rate of return of 13%. FOF 164, 164A; *compare* Examiners' Proposed Finding 234 with Commissions FOF 234. The Commission also determined to defer any decision on the prudence or imprudence of $1.453 billion of River Bend expenses. FOF 164A; COL 10; Slip Op at 5. Moreover, to effect a proper balance of consumer/investor interests, the Commission also determined that it could reexamine in a subsequent proceeding the prudence or imprudence of this amount it was holding in abeyance, and expressly concluded that it had the statutory authority and discretion to do so. COL 10. The Commission's decision to

hold in abeyance the prudence of $1.453 billion of Gulf States' River Bend expenses was a crucial element in its attempt to balance investor and consumer interests in a constitutionally permissible manner.

Critical to the balance which the Commission sought to strike was its determination to defer any decision regarding the prudence or imprudence of the $1.453 billion held in abeyance and award Gulf States only a 13% rate of return. The Commission took great pains during the Final Order meetings to make clear that there was no "disallowance" and no "write off" of the costs which it was holding in abeyance. *See* Final Order Transcript at 3318, 3517 (Greytok) and 3127 (Campbell). The Commission clearly understood the difference between disallowance and its concept of abeyance. Final Order Transcript at 2243. Under the Commission's approach, the shareholders retained their ability to seek recovery of their investment, when that investment was neither found to be prudent or imprudent. The consumers, in turn, were assured that no additional River Bend expenditures would receive rate base recognition until the Commission finally resolved the prudence issues. The "end result" of the Comission's Order thus purported to strike a proper balance between investor and consumer interests.

The majority of the Court has held that "[b]y stating that GSU failed to meet its burden of proof on the prudence of the $1.453 billion, *the PUC effectively disallowed that amount from rate base*" (Slip Op. at 6) (emphasis added), a result the Commission clearly did not reach or intend to reach. Later, the Court reasons that a permanent disallowance is not being effectuated because "[a]ll issues relating to the merits of the administrative order, including the prudence of construction costs, remain to be addressed by the trial court where the consolidated appeals of the parties are pending." *Id.*

The court's opinion ignores the fact that Gulf States had and has a constitutional right to a rate decision

which properly balances consumer and investor interests. In its decision, the Commission attempted to make that constitutionally-required balance. Holding $1.453 billion of River Bend investment in abeyance, with an opportunity for further hearings, was a crucial element of that balance. By invalidating that element, the Court has destroyed the balance which the Commission attempted to create. Yet, the Court failed to provide any mechanism to ensure that the constitutionally required balance of consumer and investor interests would be restored. As a result, the Court's opinion fails to meet the standards of the U.S. and Texas constitutions which mandates that such a balance be present in setting rates.

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